

**STATE OF NORTH CAROLINA  
UTILITIES COMMISSION  
RALEIGH**

DOCKET NO. E-100, SUB 140

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	DIRECT TESTIMONY OF GLEN A.
Biennial Determination of Avoided Cost	)	SNIDER ON BEHALF OF DUKE
Rates for Electric Utility Purchases from	)	ENERGY CAROLINAS, LLC AND
Qualifying Facilities	)	DUKE ENERGY PROGRESS, INC.

1 I. INTRODUCTION AND PURPOSE

2 Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

3 A. My name is Glen A. Snider. My business address is 400 South Tryon Street,  
4 Charlotte, North Carolina 28202.

5 Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

6 A. I am currently employed by Duke Energy as Director of Carolinas Resource  
7 Planning and Analytics.

8 Q. PLEASE DESCRIBE YOUR CURRENT RESPONSIBILITIES IN  
9 YOUR POSITION WITH DUKE ENERGY.

10 A. I am responsible for the supervision of the Integrated Resource Plans (“IRPs”)  
11 for both Duke Energy Carolinas (“DEC”) and Duke Energy Progress  
12 (“DEP”), collectively referred to as the Utilities (“Utilities”) or the Companies  
13 (“Companies”). In addition to the production of the IRPs, I have  
14 responsibility for overseeing the analytic functions related to resource  
15 planning for the Carolinas region. Examples of such analytic functions  
16 include unit retirement analysis, the analytical support for applications for  
17 certificates of public convenience and necessity (“CPCN”) for new  
18 generation, and analysis required to support the Utilities’ avoided cost  
19 calculations that are used in the biennial avoided cost rate proceedings.

20 Q. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL AND  
21 PROFESSIONAL EXPERIENCE.

22 A. My educational background includes a bachelor of science in mathematics and  
23 a bachelor of science in economics from Illinois State University. With

1 respect to professional experience, I have been in the utility industry for over  
2 twenty years. I started as an associate analyst with the Illinois Department of  
3 Energy and Natural Resources, responsible for assisting in the review of  
4 Illinois utilities' integrated resource plans. In 1992, I accepted a planning  
5 analyst job with Florida Power Corporation and for the past twelve years have  
6 held various management positions within the utility industry. These  
7 positions have included managing the Risk Analytics group for Progress  
8 Ventures and the Wholesale Transaction Structuring group for ArcLight  
9 Energy Marketing. Immediately prior to the merger of Duke Energy  
10 Corporation and Progress Energy ("Duke-Progress Merger" or "Merger"), I  
11 was Manager of Resource Planning for Progress Energy Carolinas.

12 **Q. ARE YOU INTRODUCING ANY EXHIBITS IN SUPPORT OF YOUR**  
13 **TESTIMONY?**

14 A. Yes. Snider Exhibit 1 is the Duke Energy Photovoltaic Integration Study,  
15 conducted by Pacific Northwest National Laboratory, published on March 25,  
16 2014.

17 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS**  
18 **PROCEEDING?**

19 A. The purpose of my testimony is to support the Utilities' proposed  
20 methodology for avoided capacity cost calculations and other  
21 recommendations related to the Companies' payments to qualifying facilities  
22 ("QFs") pursuant to the Public Utility Regulatory Policy Act of 1978  
23 ("PURPA"). More specifically, my testimony responds to the questions posed

1 by the North Carolina Utilities Commission (the “Commission”) in its Order  
2 in Docket E-100, Sub 140 issued on February 25, 2014 and provides further  
3 recommendations relating to the fair and appropriate calculation of avoided  
4 capacity costs used to compensate QFs under the Companies’ standard  
5 avoided cost tariffs. My testimony is organized into the following sections:

- 6 1. Explanation of the peaker methodology to calculate avoided  
7 costs under PURPA;
- 8 2. Proposed modifications to the avoided capacity cost calculation  
9 methodology;
- 10 3. Proposed modifications to the avoided energy cost calculation  
11 methodology; and
- 12 4. Proposed changes to the standard avoided cost tariff eligibility  
13 limits.

14 **Q. PLEASE SUMMARIZE THE RECOMMENDATIONS THAT YOU**  
15 **ARE MAKING TO THE COMMISSION ON BEHALF OF THE**  
16 **COMPANIES.**

17 A. As set forth in greater detail in my testimony, I make the following  
18 recommendations with respect to the calculation of avoided costs for purposes  
19 of setting rates in DEC’s and DEP’s standard avoided cost tariffs, Schedules  
20 PP-N/PP-H and CSP, respectively:

21 **OVERALL CALCULATION METHODOLOGY**

- 22 1. The Commission should approve use of the peaker methodology to  
23 establish avoided energy and avoided capacity rates;

1                    **AVOIDED CAPACITY COST CALCULATION AND**  
2                    **PAYMENT**

- 3                    2.        The Commission should establish the parameters of key inputs  
4                               used to calculate the installed cost of a combustion turbine (“CT”)  
5                               for purposes of calculating avoided capacity costs;  
6                    3.        The Commission should approve standard rates that pay capacity  
7                               credits to QFs on a per-kilowatt-hour (“kWh”) basis;  
8                    4.        The Commission should reduce the special 2.0 Performance  
9                               Adjustment Factor (“PAF”) for new small hydroelectric QFs to  
10                               1.05, but grandfather the payment of the 2.0 PAF to all existing  
11                               small hydroelectric QFs;  
12                    5.        The Commission should reduce the PAF for all new QF contracts  
13                               to 1.05.  
14                    6.        The Commission should modify the approved avoided capacity  
15                               cost calculation methodology to account for and provide relative  
16                               capacity value to QFs based on the actual need of the utility for  
17                               incremental generating capacity over the term of the standard tariff  
18                               contract;

19                    **AVOIDED ENERGY COST CALCULATION**

- 20                    7.        The Commission should modify the calculation of avoided energy  
21                               costs to recognize specific measurable integration costs imposed  
22                               on the Companies’ systems associated with intermittent solar  
23                               generation;

1           8.     The Commission should approve a modification to the calculation  
2                   of avoided energy costs to adjust for lost production cost benefits  
3                   associated with the unit being avoided by the QF purchase;

4           9.     The Commission should approve the elimination of multiple  
5                   definitions of peak and off-peak within the same rate structure and  
6                   establish a single, unified tariff schedule using Option B; and

7                   **TARIFF ELIGIBILITY**

8           10.    The Commission should reduce the eligible capacity limit for  
9                   standard tariffs from 5 megawatts (“MW”) to 100 kilowatts  
10                  (“kW”).

11                   These specific recommendations are designed to improve the accuracy  
12                   and equity in the avoided cost calculation process. These recommendations  
13                   are intended to align the costs customers pay for QF energy and capacity with  
14                   the avoided cost benefits created by such purchases. In doing so, customers  
15                   are indifferent between purchasing QF power and traditional power.

## II. CALCULATION OF AVOIDED COST RATES UNDER THE PEAKER

## **METHODOLOGY**

**Q. PLEASE DESCRIBE THE PURPOSE OF AVOIDED COST RATES.**

A. Avoided cost rates are the rates established by the Commission for power that North Carolina utilities purchase from QFs. The rates are referred to as “avoided cost rates” because PURPA provides that the rates to be paid to QFs should be at or below what it would have cost for the utility to generate the power itself (i.e. the utility’s avoided costs). Under PURPA, State regulators, such as this Commission, have the discretion to determine the specific methodology to be used to determine what constitutes avoided cost. State regulators must follow PURPA guidance that avoided costs should reflect the costs of energy and capacity that would have otherwise been incurred by a utility but for the purchase from the QF supplier. As a result, customers should be indifferent since they are neither benefited from nor harmed by the purchase from a QF.

**Q. HOW ARE THE COMPANIES' AVOIDED COSTS CALCULATED?**

A. As approved by the Commission, DEC and DEP have consistently used the “peaker methodology” to determine avoided capacity and energy costs for setting the avoided cost rates paid to QFs.

## Q. HOW DOES THE PEAKER METHODOLOGY WORK?

A. The peaker methodology is designed to determine a utility's marginal capacity and marginal energy cost, and therefore, can be applied to quantify a utility's avoided costs for purposes of pricing power purchases from QFs.

1 More specifically, the peaker methodology approximates a utility's avoided  
2 energy cost through estimates produced by generation production cost  
3 modeling. This approach assumes that when a utility's generating system is  
4 operating at equilibrium, the installed fixed capacity cost of a peaker CT plus  
5 the variable marginal energy costs of running the system will produce the  
6 marginal capacity and energy cost that a utility avoids by purchasing power  
7 from a QF. The Commission has also recognized the theoretical corollary of  
8 the peaker methodology, which provides that even if a utility's next planned  
9 unit is not a simple cycle peaker, the "peaker methodology" still accurately  
10 represents a valid estimate of the utility's avoided costs. This fact is  
11 supported by the resource planning process in which building incremental  
12 peakers for capacity and relying on the remaining system for marginal energy  
13 is always an option within the planning process. Simple cycle CTs represent  
14 the lowest capital cost resource option from a fixed cost perspective and thus,  
15 they are the marginal resource of choice. The utility only selects more  
16 expensive capital facilities, such as natural gas combined cycle baseload units,  
17 when the incremental efficiency of the unit (as compared to a simple cycle  
18 peaker) provides enough marginal energy value to more than compensate for  
19 the incremental capital. Stated simply, the fuel savings of a baseload plant  
20 will offset its higher capital costs, producing a net cost no greater than the  
21 capital costs of a peaker.

1   **Q.   PLEASE DESCRIBE THE DIFFERENCE BETWEEN AVOIDED**  
2       **ENERGY COSTS AND AVOIDED CAPACITY COSTS AS APPLIED**  
3       **UNDER THE PEAKER METHODOLOGY.**

4   A.   Avoided energy costs represent an estimate of the variable costs that are  
5       avoided and would have otherwise been incurred by the utility but for the  
6       purchase from a QF. Avoided energy costs, which are expressed in dollars  
7       per megawatt hour (\$/MWh), include items such as avoided fuel and avoided  
8       variable operation and maintenance (“VOM”) costs. Avoided capacity costs,  
9       on the other hand, represent fixed costs associated with construction,  
10      financing and staffing of a CT. The fixed costs are the annual costs incurred  
11      to have production capacity available and dispatchable on demand. These  
12      costs do not depend on the actual use of the CT but rather the costs to build  
13      the CT and have it available to meet customer demand. Fixed costs associated  
14      with one kW of capacity are normally represented as a \$/kW-Yr value for  
15      each kW of CT capacity that could be avoided. As an analogy, if one was to  
16      purchase an electric vehicle, the avoided gasoline and avoided oil changes of a  
17      gas-powered vehicle would be the equivalent of avoided energy costs, which  
18      include avoided fuel costs and VOM. In addition, to the extent the electric  
19      vehicle offsets the purchase of a gas-powered vehicle; the car payment for the  
20      gas-powered vehicle would represent the avoided fixed capacity payment. In  
21      this example, the QF (or electric vehicle) would be paid a rate equal to the  
22      avoided gasoline and oil (energy) of the gas-powered vehicle plus, to the

1 extent a gas powered vehicle was avoided, the avoided car payment for that  
2 vehicle (capacity).

3 **Q. HOW ARE AVOIDED ENERGY COSTS CALCULATED UNDER THE**  
4 **PEAKER METHODOLOGY?**

5 A. In any given hour, the Utilities will have a variety of units online such as  
6 hydro-electric, nuclear, natural gas combined cycle, coal, natural gas simple  
7 cycle CTs and diesel fuel oil CT resources. These units all have differing  
8 variable fuel and operating costs that are dispatched on an economic basis to  
9 meet instantaneous load obligations. The peaker methodology credits the QF  
10 for avoiding energy from the most expensive unit otherwise known as the  
11 marginal unit. For illustrative purposes the table below presents a simplified  
12 example of an economic dispatch for five hours given a fleet of six different  
13 10 MW generators each with differing variable fuel and operating costs.  
14 Please note that the generators come online in economic order when load  
15 grows and are taken offline in reverse order when load declines.

1

Unit Variable Costs Per Hour (\$ per MWh) Illustrative Only					
Hour ----- Load -----	Hour 1 30MW	Hour 2 40MW	Hour 3 50MW	Hour 4 50MW	Hour 5 40MW
Resources Online					
Older Fleet CT (10 MW)					
Gas CT (10 MW)			\$55	\$55	
Coal (10MW)		\$42	\$42	\$42	\$42
Combined Cycle (10 MW)	\$35	\$35	\$35	\$35	\$35
Nuclear (10 MW)	\$8	\$8	\$8	\$8	\$8
Hydro (10 MW)	\$2	\$2	\$2	\$2	\$2
Average Fuel Cost (\$/MWh)	\$15.00	\$21.75	\$28.40	\$28.40	\$21.75
Marginal Fuel Cost (\$/MWh)	\$35.00	\$42.00	\$55.00	\$55.00	\$42.00

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In the case of the peaker method, the variable costs that are deemed avoided are the variable fuel and operating costs associated with the most expensive unit in that hour. Thus, in this example, a QF producing in these hours would receive credit for avoiding the marginal fuel costs shown in the table above.

1    **Q.    IN GENERAL TERMS, HOW ARE AVOIDED CAPACITY COSTS**  
2    **CALCULATED UNDER THE PEAKER METHODOLOGY?**

3    A.    As I discuss in more detail later in my testimony, the peaker method credits  
4    avoided capacity value to the QF based on the utilities' cost to construct a  
5    simple cycle CT. These costs represent the fixed capital, financing and  
6    operating costs associated with the construction and operation of a CT facility.  
7    The fixed investment costs are then converted to an annual per unit value (\$  
8    per kW-Yr) cost that includes both the recovery-of and return-on the  
9    investment in the CT, along with the annual fixed operating costs such as  
10    staffing. Once an annual value is established, it is allocated to the on-peak  
11    hours defined in the avoided cost rate schedule. In the analogy of the QF  
12    being the electric vehicle, the avoided capacity cost is the annual car payment  
13    for the avoided gas-powered vehicle along with other fixed costs such as  
14    taxes.

15   **Q.    FOLLOWING THE EXPLANATION ABOVE, WHY IS IT**  
16   **APPROPRIATE FOR A SIMPLE CYCLE CT TO BE USED AS THE**  
17   **BASIS FOR AVOIDED CAPACITY VALUE?**

18   A.    The Companies only elect to build units more expensive than a simple cycle  
19   CT, like a natural gas combined cycle ("CC"), if the lower lifecycle fuel and  
20   other variable costs of the CC offset the higher fixed costs of the CC over the  
21   life of the facility. In that situation, the justification is that the CC not only  
22   provides reliable capacity, but also results in reduced energy costs relative to  
23   system marginal costs. In the previous example, a new CC would produce \$7

1 per MWh savings (the difference between its \$35 per MWh cost and the \$42  
2 per MWh System Marginal cost) in hours 2 and 5 while producing \$20 per  
3 MWh savings in hours 3 and 4. In comparison, a new CT, which produces  
4 reliable capacity when needed, but does not produce energy cost savings in  
5 the example because its variable costs are at or above the system's marginal  
6 cost in all five hours represented. From an avoided cost perspective, it is clear  
7 that it would be incorrect to associate the avoided fixed cost of a CC with  
8 system marginal energy costs since the CC itself produces below the marginal  
9 energy cost in some hours. As such, utilizing the CC as the avoided cost  
10 proxy would result in an avoided energy cost less than the system marginal  
11 energy cost. However, in this example, the CT does not produce below  
12 system marginal energy cost. In this instance, it would be appropriate from an  
13 avoided cost perspective to calculate both the full system marginal energy cost  
14 as the avoided energy cost and the fixed CT cost as the avoided capacity cost  
15 since the CT itself has no additional energy benefit.

16 **Q. DO THE COMPANIES RECOMMEND THE COMMISSION**  
17 **APPROVE THE CONTINUED USE OF THE PEAKER**  
18 **METHODOLOGY TO CALCULATE AVOIDED CAPACITY COSTS?**

19 A. Yes.

20 **Q. DOES THE PEAKER METHODOLOGY ALLOW THE COMPANIES**  
21 **TO FAIRLY AND APPROPRIATELY CAPTURE AND ESTIMATE**  
22 **THEIR AVOIDED COSTS OR THE COSTS THAT WOULD HAVE**

1           **OTHERWISE BEEN INCURRED BUT FOR THE PURCHASE FROM**  
2           **THE QF?**

3       A.    Yes.  If properly applied, the use of the peaker methodology provides a  
4           reasonable and appropriate estimate of the costs that would have otherwise  
5           been incurred but for the purchase from a QF facility.  The Companies are not  
6           recommending that the Commission approve a different methodology to  
7           calculate avoided costs; however, the Companies believe that application of  
8           the peaker methodology should be refined or modified in several ways.  The  
9           proposed refinements will ensure that the Companies' customers remain  
10          indifferent as to whether the Companies produce the power themselves,  
11          purchase power from the QF or obtain it from an alternative source.  The  
12          following portions of my testimony will address certain clarifications and  
13          modifications that are required to properly apply the peaker methodology  
14          consistent with PURPA.

15       **III.   PROPOSED CLARIFICATIONS AND MODIFICATIONS TO THE**  
16                               **AVOIDED CAPACITY COST CALCULATION**

17       **Q.    HOW SHOULD THE AVOIDED CAPACITY COST CALCULATION**  
18           **METHODOLOGY BE REFINED OR MODIFIED TO ENSURE**  
19           **CUSTOMERS ARE NOT PAYING MORE FOR QF CAPACITY THAN**  
20           **THE ACTUAL COSTS THAT THE UTILITY AVOIDS FROM SUCH A**  
21           **PURCHASE?**

22       A.    I recommend refining and modifying several factors in the application of the  
23           peaker methodology that relate to realigning the avoided cost rates that our

1 customers ultimately pay with value of the capacity that QFs actually deliver  
2 and our customers ultimately receive. These factors can be separated into four  
3 broad categories:

- 4 1. Calculating the key inputs influencing the estimate of annual CT  
5 capacity cost;
- 6 2. Determining the years in which the utilities actually have an avoidable  
7 capacity need;
- 8 3. Determining how annual capacity payments are made to the QF  
9 supplier; and
- 10 4. Applying an appropriate PAF.

11 **A. FACTORS INFLUENCING THE ANNUAL CT CAPACITY**

12 **COST ESTIMATE**

13 **Q. WITH RESPECT TO ANNUAL CT CAPACITY COSTS, WHAT ARE**  
14 **THE MOST PERTINENT ISSUES INFLUENCING THE ANNUAL**  
15 **CAPACITY COST ESTIMATE?**

16 **A.** Under the peaker methodology, the capacity component of avoided costs is  
17 driven primarily by the cost to install a new CT. The following inputs have a  
18 significant impact on the annual CT capacity cost calculation. Consequently,  
19 the parties debated the appropriate calculation of these inputs in the previous  
20 avoided cost case before the Commission, Docket No. E-100, Sub 136:

- 21 1. Estimates of equipment and construction costs for a simple cycle CT;
- 22 2. The appropriate contingency factor, or risk factor, to apply to the cost  
23 estimate; and

1           3.       The cost of capital and depreciable book life.

2                   When addressing varying viewpoints on these issues, we should  
3       simply ask the following basic question, “What is a reasonable estimate of  
4       anticipated CT capacity costs that could be avoided by purchasing from a  
5       QF?” In other words, when considering any one parameter, it should be  
6       viewed from an expected case, not from the vantage of extreme highs or  
7       extreme lows.

8       **Q.     WHAT RECOMMENDATIONS FOR THESE FACTORS AFFECTING**  
9       **THE CALCULATION OF THE ANNUAL CT CAPACITY COST ARE**  
10      **THE COMPANIES PROPOSING?**

11     A.     The following general guidelines should be adopted in the calculation of the  
12     annual fixed CT capacity costs:

- 13       1.     Cost estimates should be based on the Companies’ most recent study of  
14             installed CT costs combined with past construction and operations  
15             experience.
- 16       2.     Equipment and construction costs should be based on the cost estimate  
17             for a four unit greenfield site.
- 18       3.     Direct CT interconnection costs should be included, but any estimates of  
19             downstream transmission and distribution (“T&D”) system upgrade  
20             costs should be excluded.
- 21       4.     The equipment and construction costs should represent an expected  
22             construction cost with neither a best case nor worst case contingency  
23             adder included. Instead, the Companies should use a contingency factor

1                   that, when applied, would result in an expected cost to construct. The  
2                   Companies' position is that a five percent contingency adder results in a  
3                   reasonable expected construction cost.

4           5.   The annual capacity value of a CT should be calculated incorporating  
5                   the Companies' most recently approved cost of capital and book life  
6                   assumptions for a CT. The Companies recommend a 35-year book life  
7                   for purposes of avoided capacity cost calculations.

8   **Q.   PLEASE EXPLAIN THE BASIS FOR THE COMPANIES' POSITION**  
9           **THAT THE CT COST ESTIMATE UTILIZED FOR AVOIDED**  
10           **CAPACITY COST SHOULD BE BASED ON A FOUR UNIT**  
11           **GREENFIELD SITE.**

12   A.   The avoided capacity cost calculation should reflect the economies of scale  
13           associated with building four CTs at a greenfield site. This is supported by the  
14           Utilities' demonstrated practice of building multiple CTs at a single site. Of  
15           all DEP's CT sites, only the Asheville site has fewer than four CTs on the  
16           site. This is due specifically to the unique characteristics of the Asheville  
17           area. Similarly, three of DEC's four CT sites have four or more units. The  
18           fourth is a two-unit site that is utilized as a back-up source of generation to a  
19           nuclear site. Because the Companies typically construct CTs with at least four  
20           units at a site, it is reasonable to use the four-unit configuration as the basis  
21           for their avoided capacity rates. Furthermore, in using the average cost of a  
22           four-unit site, the Utilities are following DEP's standard practice of  
23           constructing four CTs at a plant site.

1           The Utilities will continue to pursue CT development as an option  
2           to meet their obligation to provide least cost power to their customers. The  
3           multiple unit approach is the most cost-effective approach to developing CTs  
4           because it optimizes the economies of scale associated with construction.  
5           The cost of land, site preparation, roadways, gas infrastructure, electric  
6           transmission infrastructure, water infrastructure, and administrative and  
7           auxiliary buildings is spread among several units (instead of just one or two).  
8           In practice, the Companies would first evaluate brownfield options in order to  
9           locate a CT at an existing generation facility with much of the infrastructure  
10          already in place. This would likely yield an even lower cost than the four unit  
11          greenfield site. The Companies' recommendation for a four unit greenfield  
12          site represents a reasonable, balanced estimate for the avoidable construction  
13          cost of a CT.

14   **Q.   PLEASE EXPLAIN WHY YOU RECOMMEND INCLUSION OF**  
15       **INTERCONNECTION AND EXCLUSION OF T&D NETWORK**  
16       **SYSTEM UPGRADE COSTS IN CALCULATING AVOIDED**  
17       **CAPACITY RATES.**

18   A.   Interconnection costs include costs associated with physically connecting the  
19          generation source to the transmission system, such as the switchyard and  
20          associated equipment costs. These interconnection costs are included in the  
21          calculation of avoided cost rates because they are real costs that will be  
22          avoided when avoiding the construction of a new CT and because the QF is

1 fully responsible for the interconnection costs associated with its own  
2 facility.

3 Network upgrade costs, unlike interconnection costs, involve  
4 improvements to the transmission system beyond merely connecting a  
5 generation resource to the transmission system. Such upgrades are needed  
6 to accommodate the anticipated increases in power flows as growing load is  
7 met from sources such as new generating facilities or new power purchases.  
8 Sometimes a utility's construction of new generation facilities will require  
9 transmission upgrades, but not all new generation additions require such  
10 upgrades. A number of factors, including the current state of the transmission  
11 system, the amount and type of generation being added to the system, and the  
12 location of the new generation can influence whether T&D network  
13 upgrades are required by the addition of new generation. Moreover, T&D  
14 network upgrades can range from minor additions such as a bank of  
15 capacitors to enormously expensive undertakings such as the construction  
16 of a new transmission line. All other things being equal, utilities will try to  
17 plan their generation additions to avoid or minimize the need for network  
18 upgrades. As the foregoing makes clear, although all generation additions  
19 require interconnection, not all generation additions necessitate network  
20 upgrades. Furthermore, transmission and distribution system circuits are  
21 designed for peak load conditions on a circuit. Placing intermittent generation  
22 on a circuit does not change the need for transmission infrastructure at the  
23 time of the circuit's peak since the transmission infrastructure needs to bring

1 in power from elsewhere on the system at times when the generation is not  
2 available. As load grows on a circuit, intermittent generation does not  
3 alleviate the need for incremental transmission investment, and as such,  
4 should not be credited with avoided transmission system upgrade costs.

5 **Q. PLEASE DEFINE CONTINGENCY FACTOR AND EXPLAIN ITS**  
6 **PURPOSE.**

7 A. A contingency factor (or contingency allowance) is an amount added to a  
8 project cost estimate to account for uncertainties and risks. It is usually  
9 expressed as a percentage of the project cost estimate. One helpful definition  
10 of contingency that I find useful for the present case is the one used by the  
11 Energy Information Administration (“EIA”). EIA uses contingencies in its  
12 annual estimate of the cost of installing various types of electric generating  
13 facilities and describes the purpose of the contingency adders it uses as  
14 follows:

15 A contingency allowance is defined by the American Association of  
16 Cost Engineers as the “specific provision for unforeseeable elements  
17 of costs within a defined project scope; particularly important where  
18 previous experience has shown that unforeseeable events which will  
19 increase costs are likely to occur.”

20 A 5% contingency adder represents an “expected case scenario” and is  
21 appropriate in the context of building a conventional CT for purposes of the  
22 Utilities’ avoided capacity rates.

1   **Q.     WHY DO YOU BELIEVE A 5% CONTINGENCY ADDER REFLECTS**  
2           **AN “EXPECTED CASE” IN THE CONTEXT OF BUILDING A**  
3           **CONVENTIONAL CT FOR PURPOSES OF THE UTILITIES’**  
4           **AVOIDED CAPACITY RATES?**

5   A.     The Utilities believe that a 5% contingency adder adequately reflects an  
6           “expected case” in the context of building a conventional CT for purposes of  
7           avoided cost rates. In keeping with the EIA definition provided above, all of  
8           the Utilities’ recent experience with constructing combustion turbine-based  
9           generation points to the same conclusion – large contingency adders are not  
10          warranted in estimating the cost of those types of projects.

11                 Since 2009, DEP has completed four projects involving plants with  
12                 combustion turbine technology – the Wayne County CT, the Smith CC, the  
13                 Lee CC and the recently completed Sutton CC. The original project estimate  
14                 for those projects included contingency adders of 3-5%. All of these projects  
15                 were completed below the budgeted levels inclusive of the stated contingency.  
16                 Moreover, of these four projects, only the Wayne County CT ended up using  
17                 any of its contingency while the rest came in enough below budget to result in  
18                 negative contingency.

19                 DEC’s recent experience with combustion turbine technology projects  
20                 is consistent with DEP’s experience. In November 2011, a new combined  
21                 cycle unit began commercial operation at DEC’s Buck Combined Cycle  
22                 Station and, in December 2012, DEC added a combined cycle unit to the Dan  
23                 River Combined Cycle Station. The initial project estimates for both the new

1 Dan River and Buck units contained contingency adders of 4%. Both the  
2 Buck and Dan River CCs were completed under budget and used none of the  
3 contingency included in the original cost estimate. Thus, DEC's recent  
4 combustion turbine technology projects also demonstrate a 5% contingency  
5 allowance is a reasonable estimate of contingency.

6 In sum, both DEC's and DEP's actual experience over the past years  
7 in constructing six combustion turbine technology generation projects clearly  
8 shows that a reasonable contingency adder is between 3% and 5%. DEC and  
9 DEP have been able to complete construction and achieve commercial  
10 operation using less contingency than projected or none at all. Indeed, the  
11 Utilities could argue that no contingency adder is required for simple cycle  
12 CTs because they are far less complex than the utilities' recent construction of  
13 CCs. However, consistent with the premise of seeking a balanced approach to  
14 each of these parameters, the Utilities support the use of 5% contingency  
15 adder as a basis for avoided CT costs.

16 **Q. WITH RESPECT TO THE ASSUMED USEFUL LIFE OF CTS,**  
17 **PLEASE EXPLAIN HOW THAT FACTOR AFFECTS THE CT COSTS**  
18 **USED IN CALCULATING AVOIDED CAPACITY RATES.**

19 A. As previously noted, the capacity component of avoided costs under the  
20 peaker methodology is driven primarily by the cost to install a new CT. That  
21 cost is levelized over the CT's useful life to set the avoided capacity rates.  
22 Thus, a longer useful life provides a longer period of time over which to  
23 spread the capital costs of the CT, which translates to a lower annualized

1 capital cost and lower avoided capacity rates. For example, assuming two  
2 CTs with identical construction costs and identical capacity ratings, if one CT  
3 is expected to operate for 30 years and the other is expected to operate for 40  
4 years, the annual levelized capital cost of the 40-year CT will be lower  
5 because its capital costs will be spread over a longer time period. Similarly,  
6 for purposes of avoided cost rates, an assumption of a longer useful life for a  
7 CT translates to lower annual capital costs and lower avoided capacity rates,  
8 all other things being equal. A simple analogy would be two homes that cost  
9 the same amount, but one is financed over 15 years and the other over 30  
10 years. The annual mortgage payments for the home financed over 30 years  
11 will be smaller than the mortgage payment for the home financed over 15  
12 years.

13 **Q. WHY IS 35 YEARS A REASONABLE ASSUMPTION FOR THE**  
14 **USEFUL LIFE?**

15 A. Avoided capacity rates should reflect the capital costs the purchasing utility  
16 actually avoids if it purchases power from a QF rather than generating the  
17 power itself. PURPA's directive, which states that the rates paid shall not  
18 exceed the purchasing utility's avoided cost, is intended to protect utility  
19 customers from bearing higher costs as a result of the utility's QF power  
20 purchases. It follows from these two principles that the best reference points  
21 for determining the useful life of a CT to be used in setting avoided cost rates  
22 are: (1) the actual operating lives of the utility's CT fleet; and (2) the CT  
23 useful life assumptions used in setting the utility's base rates. The actual

1 operating lives of a utility's CTs are relevant in assessing the capacity cost  
2 assumed to be avoided by purchasing from a QF. The useful life assumptions  
3 used for ratemaking measures the avoided costs from the customers'  
4 perspective. In this case, both the actual operating lives of the Utilities' CT  
5 and the useful life assumptions used for setting the Utilities' rates support the  
6 use of a 35-year useful life in setting the Utilities' avoided cost rates.

7 **Q. PLEASE ELABORATE.**

8 A. First, the vast majority of the CTs on the Utilities' systems has operated or is  
9 expected to operate for 35 years or more. In other words, the Utilities'  
10 combined experience with building and operating dozens of CTs over four  
11 decades conclusively demonstrates that CTs have useful life expectancies well  
12 in excess of 30 years. If anything, the Utilities' actual experience could  
13 support a longer useful CT life than 35 years.

14 Second, as to the useful life assumptions applied in the Utilities' most  
15 recent general rate cases, each of the Utilities independently completed  
16 updated depreciation studies which support their proposed depreciation rates.  
17 DEP's most recent depreciation study uses a 40-year useful life for its CTs. In  
18 DEC's most recent depreciation study, the lifespan of a new CT was  
19 considered to be 35 to 40 years with an emphasis on 35 years based on  
20 utilization. Thus, in terms of how long a CT should be expected to operate  
21 *and* in terms of the cost customers bear for a CT in rate base, the Utilities  
22 could justify a useful life in the range of 35 to 40 years in setting avoided cost  
23 rates. Once again, while a longer useful life could be argued, the use of 35-

1 year useful life represents a reasonable middle ground for determination of  
2 this parameter.

3 **B. DETERMINING THE YEARS IN WHICH THE UTILITIES**  
4 **HAVE AN AVOIDABLE CAPACITY NEED**

5 **Q. UNDER THE CURRENTLY APPROVED AVOIDED CAPACITY**  
6 **COST CALCULATION METHODOLOGY, IS THE UTILITIES'**  
7 **RELATIVE NEED FOR INCREMENTAL GENERATING CAPACITY**  
8 **TAKEN INTO ACCOUNT?**

9 A. No. The current methodology, as applied under the standard tariff, pays a QF  
10 for capacity irrespective of the utilities' actual need for capacity. For  
11 example, if a recession occurs, the utilities' IRPs may show the next utility  
12 capacity need to be several years into the future. However, as currently  
13 calculated, the capacity value incorporated in the standard tariff avoided cost  
14 rate would ignore this fact and assume the utility had an avoidable capacity  
15 need in every year.

16 **Q. SHOULD THE UTILITIES' NEED FOR CAPACITY BE ACCOUNTED**  
17 **FOR IN THE CALCULATION OF THE AVOIDED CAPACITY**  
18 **PAYMENT?**

19 A. Yes.

20 **Q. PLEASE EXPLAIN HOW THE NEED FOR CAPACITY SHOULD BE**  
21 **ACCOUNTED FOR IN CALCULATING AVOIDED CAPACITY**  
22 **PAYMENTS.**

1 A. Under PURPA, utilities should not require their customers to pay for QF  
2 capacity unless there is an associated capacity cost to be avoided. Without  
3 modification, the current approach violates this principle and results in the  
4 Companies' customers paying for QF capacity that does not offset needed  
5 utility capacity. As a result, retail customers are paying avoided costs for  
6 capacity the Companies do not need – in excess of the Utilities' avoided  
7 capacity cost, as determined under the peaker methodology.

8 **Q. HOW DO YOU RECOMMEND THE RELATIVE NEED FOR**  
9 **INCREMENTAL GENERATING CAPACITY BE INCLUDED IN THE**  
10 **CALCULATION OF THE AVOIDED CAPACITY PAYMENT?**

11 A. As I explained earlier in my testimony, avoided capacity costs are represented  
12 on an annual basis in a similar fashion to the fixed cost of a car or home being  
13 represented as an annual car payment or mortgage payment. To appropriately  
14 incorporate the need for capacity consistent with PURPA, the annual fixed  
15 capacity costs that go into the avoided cost rate should include only the annual  
16 fixed capacity costs for years in which an actual capacity need exists as  
17 determined by the utilities' most recently filed IRP, with adjustments as  
18 discussed below.

19 **Q. HOW WOULD THE IRP BE UTILIZED TO DETERMINE WHEN**  
20 **THERE IS AN AVOIDABLE CAPACITY NEED?**

21 A. The IRP presents a 15-year resource plan that identifies when the next  
22 generation unit is needed for reliability purposes. Prior to the year in which  
23 the next generation unit is needed, the utility does not have a capacity need to

1           avoid. Thus, the calculation of the capacity portion of the avoided cost rate  
2           should not ascribe value for years prior to the first avoidable capacity need.

3   **Q.   PLEASE EXPLAIN HOW EXISTING AND FORECASTED QFS**  
4           **IMPACT THE DETERMINATION OF WHEN A UTILITY HAS AN**  
5           **AVOIDABLE CAPACITY NEED.**

6   A.   The IRP forecast for needed new generation accounts for both existing and  
7           forecasted QFs that defer the need for the next utility generator. In  
8           determining when new capacity is first needed, the utility would first remove  
9           all undesignated QFs (QFs not yet under contract) to see if the need for  
10          capacity moves forward in time. This will allow the Companies to more  
11          accurately forecast the next year in which additional capacity is required.  
12          This adjustment would ensure that the new QFs are being compensated for  
13          capacity for years in which there are an actual capacity need to avoid.

14   **Q.   DOES ACCOUNTING FOR THE TIMING OF NEEDED CAPACITY**  
15          **MORE ACCURATELY VALUE THE CAPACITY BEING**  
16          **DELIVERED BY THE QF, CONSISTENT WITH THE INTENT OF**  
17          **PURPA?**

18   A.   Yes. PURPA's clear intent is to estimate costs that, but for purchase from the  
19          QF, would have otherwise been incurred by the utility and its customers.  
20          Let's assume that economic conditions combined with a large influx of QFs  
21          eliminated all future need for utility fossil generation capacity. In such an  
22          example, incremental QFs would still avoid marginal fuel and production  
23          costs (avoided energy value); however, there would be no fixed costs to offset

1 or avoid. Under those circumstances, the payment of avoided capacity would  
2 clearly be inconsistent with PURPA. Under the current avoided capacity cost  
3 calculation, however, customers would continue to pay for QF capacity even  
4 though there is no capacity cost to be avoided. While today's situation is not  
5 to the extreme of the example above, the same principle applies. This PURPA  
6 principle requires the recognition that if the utility's first avoidable capacity  
7 need is several years in the future, then the present avoided capacity rate  
8 should only reflect value in that future period when there is a capacity need to  
9 avoid.

10 **Q. DOES THIS IMPLY THAT QFS UNDER THE TARIFF RECEIVE NO**  
11 **CAPACITY PAYMENT IN YEARS PRIOR TO THE UTILITIES'**  
12 **FIRST CAPACITY NEED?**

13 **A.** No. This simply implies the capacity rate received by the QF would reflect a  
14 lower annual payment to account for the initial years in which no avoidable  
15 capacity costs would be included in the rate derivation. In essence, the QF  
16 will receive capacity payments immediately in recognition of future avoided  
17 capacity so long as the utility has an avoidable capacity need sometime within  
18 the life of the tariff period.

19 **Q. IS THE CONSIDERATION OF THE NEED FOR CAPACITY IN THIS**  
20 **CALCULATION FAIR TO THE COMPANIES' CUSTOMERS?**

21 **A.** Yes. With the adjustments suggested, the utilities' customers would only be  
22 paying QF capacity payments equal to the economic value of an associated  
23 avoided utility capacity cost.

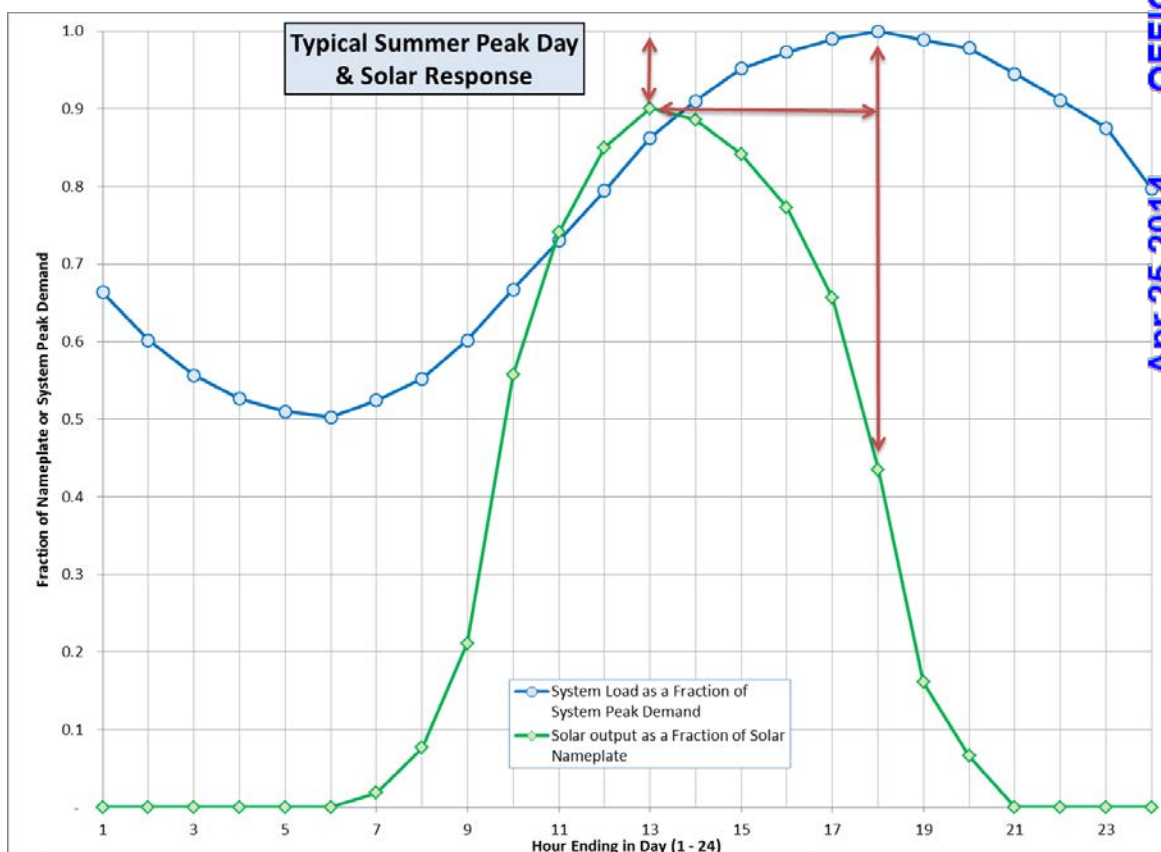
1           C.     **DETERMINING HOW ANNUAL CAPACITY IS PAID TO THE**  
2                           **QF SUPPLIER**

3     **Q.     SINCE INTERMITTENT RESOURCES ARE NOT DISPATCHABLE,**  
4           **SHOULD ANNUAL CAPACITY PAYMENTS BE MADE SIMPLY**  
5           **BASED ON THE INSTALLED CAPACITY OF EACH PROVIDER?**

6     A.     No. Such an approach would be inconsistent with the letter and intent of  
7           PURPA because the amount of installed nameplate capacity of an intermittent  
8           QF resource (expressed in kW) does not translate to an equivalent amount of  
9           avoided capacity as described earlier in my testimony.

10                   Payment based upon installed capacity fails to recognize actual  
11           performance by the generator which would lead to over-compensation relative  
12           to the value of the actual avoided capacity realized by customers. Consider  
13           the following graph which shows an example of a solar production profile on  
14           a clear sky peak summer day compared to a utility load profile for the same  
15           day. This graphic illustrates two important facts concerning the installed  
16           capacity of a solar facility. First, on a summer day solar output does not  
17           typically reach its rated installed nameplate capacity since solar panels do not  
18           perform as well on hot, humid summer days as they do in the spring and the  
19           fall.

1 Second, the availability of capacity does not coincide with the peak demand  
2 needs of the utilities' customers.



3  
4 **Q. WHAT METHOD DO THE COMPANIES RECOMMEND FOR**  
5 **PAYING QFS FOR CAPACITY VALUE?**

6 A. The Companies recognize that traditional methods of paying for capacity  
7 based on requirements of deliverability or after-the-fact comparisons to  
8 system peak are particularly problematic for smaller intermittent QF  
9 resources. To overcome these deliverability challenges and the coincident  
10 peak ("CP") demand metering challenges, the Companies recommend that  
11 annual capacity be paid on a per-kWh basis across a pre-determined set of

1 seasonal hours that represent the most likely hours in which capacity will have  
2 value.

3 **Q. HAVE THE COMPANIES SPECIFICALLY IDENTIFIED THESE**  
4 **HOURS WHEN QFS WILL PROVIDE CAPACITY VALUE?**

5 A. Not at this time. The Companies are continuing to study this issue and do not  
6 have a specific recommendation at this time; we anticipate having a  
7 recommended set of hours to share with the Commission in our next  
8 testimony filing in this docket. The goal of defining these hours will be to  
9 provide certainty to generators and to overcome the issues associated with  
10 deliverability based billing or after-the-fact CP based billing. Furthermore,  
11 the identification of these hours will incent development of solar projects that  
12 maximize output at times when capacity has the most value to the Companies'  
13 customers. Array orientation, angle and tracking options can be optimized to  
14 achieve maximum payment while considering the tradeoff of the cost of such  
15 tracking mechanisms.

16 **D. APPROPRIATE APPLICATION OF A PAF**

17 **Q. PLEASE EXPLAIN WHAT A PAF IS AND HOW IT WORKS.**

18 A. The PAF is a simple multiplier that is applied to the avoided capacity rates  
19 paid by the Companies' customers to QFs. This multiplier increases the  
20 avoided capacity rate paid by customers and received by the QF. Currently,  
21 the PAF applied to the avoided capacity rates for small hydro-electric QFs  
22 with no storage capacity is 2.0, and the PAF applied to the avoided capacity  
23 rates for all other QFs is 1.2. For example, if the avoided capacity rate is

1           \$0.05/kWh, applying a PAF of 2.0 would increase the rate to \$0.10/kWh,  
2           doubling the amount paid to the QF for capacity.

3   **Q.    WHAT IS THE RATIONALE FOR THE CURRENT 1.2 PAF?**

4   A.    Multiple perspectives have been offered as the rationale of the 1.2 PAF.  
5           Some suggest that the PAF is a required adjustment for utility reliability  
6           equivalence and others that the PAF is a required adjustment to make QFs  
7           financially equivalent to utility-owned renewable generation.

8   **Q.    WHY DO SMALL HYDROELECTRIC QFS RECEIVE A PAF OF 2.0,**  
9           **AS OPPOSED TO THE PAF OF 1.2 APPLIED TO OTHER QFS?**

10 A.    My understanding is that the Commission concluded that a larger PAF was  
11           justifiable for small hydroelectric QFs because the North Carolina General  
12           Assembly had enacted a policy generally supporting the continued operation  
13           of the State's small hydroelectric facilities.

14 **Q.    SHOULD SMALL HYDROELECTRIC FACILITIES CONTINUE TO**  
15 **RECEIVE A PAF OF 2.0 AS PART OF THEIR AVOIDED CAPACITY**  
16 **RATES?**

17 A.    No. For the reasons I give below, new small hydro facilities should not  
18           receive a 2.0 PAF in calculating their avoided cost capacity rates, and Witness  
19           Bowman addresses this issue from a policy perspective in her testimony. For  
20           the reasons given by Ms. Bowman, I would agree, however, that it is  
21           appropriate for existing, small hydroelectric facilities to continue to receive a  
22           2.0 PAF.

1    **Q.    IS THERE ANY JUSTIFICATION FOR DIFFERENT PAFS FOR**  
2    **DIFFERENT RESOURCES?**

3    A.    No. On a going forward basis any form of adjustment made to the avoided  
4    capacity value should be based on the avoided CT, not the particular QF  
5    resource. In developing avoided cost rates, the peaker methodology  
6    appropriately seeks to identify avoidable utility costs irrespective of the  
7    particular QF resource avoiding those costs.

8    **Q.    IN YOUR OPINION, WHAT WOULD BE AN APPROPRIATE BASIS**  
9    **FOR A PAF?**

10   A.    The PAF should be established based on the reliability of the avoided unit, a  
11   CT.

12   **Q.    WHAT IS THE RELIABILITY OF A CT, THE AVOIDED UNIT?**

13   A.    The appropriate measure of reliability for a combustion turbine peaking unit is  
14   the starting reliability. The Companies' starting reliability target for the CT  
15   fleet is 98.5%. Actual data was compiled for the years 2011 through 2013  
16   which showed a successful start rate for the combined DEC and DEP large  
17   frame CTs of approximately 99%.

18   **Q.    WHAT RELIABILITY STANDARDS DO THE UTILITIES APPLY TO**  
19   **PURCHASE POWER CONTRACTS FROM THIRD PARTY**  
20   **GENERATORS?**

21   A.    In reviewing its purchase power contracts from third party natural gas  
22   generators, the Companies generally allow the third party generator to receive  
23   their full contractual capacity payment so long as they maintain a minimum

1           availability level. This level varies by contract but is generally in a range  
2           between 94% to 98%. Extrapolating to a reliability based PAF, this level of  
3           reliability would equate to approximately a 1.02 to 1.06 PAF. To illustrate - if  
4           the capacity payment was based upon delivering over peak hours within a  
5           given month, the third party provider that had 97% deliverability would  
6           receive a PAF of 1.03. As such, in the example, if the provider was 100%  
7           reliable, it would actually receive a 3% bonus above its capacity payment. If,  
8           on the other hand, the provider was 97% available, it would receive its full  
9           capacity payment since 0.97 (availability) times a 1.03 (PAF) would equal 1.

10   **Q.    IF A RELIABILITY-BASED PAF WERE TO BE ADOPTED, WHAT IS**  
11   **THE COMPANIES' RECOMMENDED PAF?**

12   A.    The projected reliability of new CTs that form the basis of the avoided cost  
13           payment would suggest a PAF of approximately 1.02. The broader range of  
14           1.02 to 1.06 is justified if the QF capacity purchase is viewed in a manner  
15           similar to other more traditional wholesale power purchases. In keeping with  
16           the stated objective of neither seeking the highest or lowest value that could  
17           reasonably be justified, the Companies recommend a 1.05 PAF.

1           **IV.   PROPOSED CLARIFICATIONS AND MODIFICATIONS TO**  
2           **THE AVOIDED ENERGY COST CALCULATION METHODOLOGY**

3   **Q.   DO THE COMPANIES ALSO PROPOSE SPECIFIC ADJUSTMENTS**  
4           **TO THE CURRENT METHODOLOGY FOR THE CALCULATION**  
5           **OF AVOIDED ENERGY COSTS?**

6   A.   Yes, the current calculation of avoided energy rates should be adjusted to  
7           ensure that the Companies' customers are paying for the true value of the QF  
8           energy being delivered.

9   **Q.   WHAT ADJUSTMENTS DO THE COMPANIES RECOMMEND?**

10   A.   The following three adjustments to the avoided energy calculation would  
11           better align customer payment for QF energy with the utility's avoided costs  
12           associated with the QF purchase:

- 13           1.       The recognition of specific measurable integration costs associated  
14                      with intermittent solar generation;
- 15           2.       Adjusting for lost production cost benefits associated with the unit  
16                      being avoided through the purchase of QF power; and
- 17           3.       The elimination of multiple definitions of peak and off-peak within the  
18                      tariff structure by eliminating the Companies' respective Option A  
19                      schedules.

20           As with the changes proposed regarding avoided capacity costs, these  
21           proposed changes are intended to allow the Companies to more accurately and  
22           appropriately capture their actual avoided costs.

1           A.     THE RECOGNITION OF SPECIFIC MEASURABLE  
2                     INTEGRATION COSTS ASSOCIATED WITH  
3                     INTERMITTENT SOLAR GENERATION

4     Q.     WHAT IS THE BASIS OF YOUR RECOMMENDATION THAT  
5             CERTAIN INTEGRATION COSTS BE REFLECTED IN THE  
6             AVOIDED COST CALCULATION?

7     A.     Intermittent QF resources, specifically solar, produce avoided energy and  
8             capacity value for the Companies' customers. However, the nature of such  
9             resources also creates integration costs as identified in the recently published  
10            Duke Energy Photovoltaic Integration Study ("Duke Energy PV Study"),  
11            conducted by Pacific Northwest National Laboratory, which is attached to my  
12            testimony as Snider Exhibit 1. These integration costs slightly reduce the  
13            avoided energy benefits of solar QFs as currently calculated.

14    Q.     WHAT ARE THE INTEGRATION COSTS YOU ARE  
15             RECOMMENDING TO OFFSET AVOIDED ENERGY BENEFITS  
16             RECEIVED FROM SOLAR QFS?

17    A.     I recommend the recognition of the integration costs associated with the  
18             increased reserve requirements in the Generation section of the Duke Energy  
19             PV Study. These represent the increase in net load variability due to solar  
20             photovoltaic ("PV") penetration. Reserves were defined in the study as  
21             follows:

- 22             • Day-ahead planning reserve ("DA PR"): Additional generation
- 23             required in DA planning that is intended to mitigate forecast errors

1 (uncertainty), within-hour variability and loss of generation. However,  
2 it is assumed that the current contingency reserve requirement (as  
3 dictated by the VACAR Reserve Sharing Group) does not increase  
4 regardless of the amount of PV integration. With respect to this study,  
5 DA PR refers only to the components associated with forecast  
6 uncertainty and variability with system generation and load.

- 7 • Regulation reserve (“RR”): The reserve needed to cover minute-by-  
8 minute variations of load and PV. RR requires fast response and  
9 therefore must be provided by units on automatic generation control  
10 (“AGC”). RR is also a component of DA PR.

11 Additional detailed discussion of reserve definitions is included in  
12 section 2.2.4 in Snider Exhibit 1.

13 **Q. WHAT INTEGRATION COST DO YOU RECOMMEND FOR USE IN**  
14 **THE PROPOSED ADJUSTMENT TO AVOIDED COST?**

15 A. The study evaluated 3 scenarios of PV penetration across a 10 year period. I  
16 recommend the use of the Compliance case, which aligns with the IRP  
17 assumptions for PV penetration and is the lowest penetration level considered  
18 in the study. The energy rate that applies to solar QFs in the avoided cost  
19 docket should be adjusted to reflect the study results, albeit at the lowest end  
20 of the range identified within the study, based on the current level of solar QF  
21 integration into the Companies’ systems.

1           **B.     ADJUSTING FOR LOST PRODUCTION COST BENEFITS**  
2                           **ASSOCIATED WITH THE AVOIDED CT**

3   **Q.     WHY IS AN ADJUSTMENT NECESSARY TO ACCOUNT FOR THE**  
4           **LOST PRODUCTION COST BENEFIT ASSOCIATED WITH THE**  
5           **AVOIDED CT?**

6   A.     The adjustment is necessary to accurately reflect the avoided cost of the CT.  
7           CTs have become more efficient over time with newer CTs being more  
8           efficient than many of the older CTs on the Companies' systems. In years  
9           past, a new CT may have only been expected to run less than one percent of  
10          the time and, when it did run, it would have been expected to set the marginal  
11          energy price in that hour. Stated another way, the avoided CT would have  
12          rarely expected to operate since its operation costs would have been above  
13          system marginal costs in any hour. To illustrate this point, consider the  
14          original example I presented at the beginning of my testimony:

1

Unit Variable Costs Per Hour (\$ per MWh) Illustrative Only					
Hour ----- Load -----	Hour 1 30MW	Hour 2 40MW	Hour 3 50MW	Hour 4 50MW	Hour 5 40MW
Resources Online					
F-Frame CT (10 MW)			\$55	\$55	
Coal (10 MW)		\$42	\$42	\$42	\$42
Combined Cycle (10 MW)	\$35	\$35	\$35	\$35	\$35
Nuclear (10 MW)	\$8	\$8	\$8	\$8	\$8
Hydro (10 MW)	\$2	\$2	\$2	\$2	\$2
Average Fuel Cost (\$/MWh)	\$15.00	\$21.75	\$28.40	\$28.40	\$21.75
Marginal Fuel Cost (\$/MWh)	\$35.00	\$42.00	\$55.00	\$55.00	\$42.00

2                    In this example the avoided CT would have created no marginal fuel  
3 savings for the customer. Rather it would have simply provided capacity  
4 value for the very few hours it was needed. Since the avoidable CT produces  
5 at \$55 per MWh there are simply no hours in which the system marginal  
6 energy cost is above that of the CT. Over time this dynamic has changed with  
7 newer CTs becoming more efficient. Consider the following additional  
8 example that illustrates this transition.

Unit Variable Costs Per Hour (\$ per MWh) Illustrative Only					
Hour ----- Load -----	Hour 1 30MW	Hour 2 40MW	Hour 3 50MW	Hour 4 50MW	Hour 5 40MW
Resources Online					
Older Fleet CT (10 MW)			\$70		
F-Frame CT (10 MW)			\$55	\$55	
Coal (10 MW)		\$42	\$42	\$42	\$42
Combined Cycle (10 MW)	\$35	\$35	\$35	\$35	\$35
Nuclear (10 MW)	\$8	\$8	\$8	\$8	\$8
Hydro (10 MW)	\$2	\$2	\$2	\$2	\$2
Average Fuel Cost (\$/MWh)	\$15.00	\$21.75	\$35.33	\$28.40	\$21.75
Marginal Fuel Cost (\$/MWh)	\$35.00	\$42.00	\$70.00	\$55.00	\$42.00

1                   The example above introduces a utility system that has older, less  
2                   efficient CTs on the system. These older CTs have a variable energy cost in  
3                   excess of the newer F-Frame CTs. In this example, the avoidable unit, the F-  
4                   Frame CT, produces a \$15 per MWh production cost benefit in Hour 3.  
5                   Hence, by avoiding the CT, the utility loses that production cost benefit.

1    **Q.    WHAT ADJUSTMENT TO THE ENERGY CALCULATION IS**  
2           **REQUIRED TO ENSURE CUSTOMERS ARE NOT PAYING MORE**  
3           **FOR QF ENERGY THAN THE AVOIDED ENERGY VALUE?**

4    A.    In the calculation of the avoided energy payment, the hourly production costs  
5           savings calculated in the system dispatch model should be capped at the  
6           production cost of the avoided CT. Once again from the prior example, this  
7           cap simply recognizes that while the QF is avoiding the \$70 marginal energy  
8           in hour 3, the avoided CT would have also avoided the \$70 marginal energy  
9           cost in hour 3, effectively replacing it with the CT's \$55 energy cost. Capping  
10          marginal energy cost in each hour at the avoided energy cost of the CT results  
11          in an avoided energy calculation that aligns customer payments for QF energy  
12          with the avoidable energy benefit produced by the QF. This leaves the  
13          customer indifferent between QF energy and utility system energy. Without  
14          this adjustment the customer is paying more for QF energy than is actually  
15          avoided by the utility through the purchase of QF power.

16   **Q.    WOULD THE ENERGY CAP BE APPLIED IN ALL YEARS OF THE**  
17          **QF CONTRACT?**

18   A.    No. As previously discussed in my testimony, the utility may not have an  
19          avoidable capacity need in all years. Consistent with the recommendation on  
20          capacity, capping the avoided energy at the avoidable CT production cost  
21          would only be applied starting in the first year of an avoidable need.

1           C.     ELIMINATION OF MULTIPLE DEFINITIONS OF PEAK AND  
2                     OFF-PEAK WITHIN THE COMPANIES' TARIFF  
3                     STRUCTURES

4     Q.     WHAT HOURS DEFINE ON-PEAK ENERGY VS. OFF-PEAK  
5             ENERGY IN THE COMPANIES' CURRENT STANDARD AVOIDED  
6             COST TARIFFS?

7     A.     The Companies' respective avoided cost tariffs both allow QFs to choose  
8             between two different on-peak rate definitions defined as Option A and  
9             Option B within the rate. The on-peak energy hours for DEP's Schedule CSP  
10            and DEC's Schedules PP-N and PP-H are provided in the table below.

DEP: Schedule CSP		
Option A:	April – September	10:00am – 10:00pm
	October – March	6:00am – 1:00pm, 4:00pm – 9:00pm
Option B:	June – September	1:00pm – 9:00pm
	October – May	6:00am – 1:00pm
DEC: PP-N, PP-H		
Option A:	June – September, December – March	7:00am – 11:00pm
Option B:	June – September	1:00pm – 9:00pm
	October – May	6:00am – 1:00pm

11  
12     Q.     SHOULD THE AVOIDED COST ENERGY RATE BE LIMITED TO A  
13             SINGLE DEFINITION OF PEAK HOURS?

14     A.     Yes. The standard tariff should define a single set of hours as on-peak for  
15             purposes of calculating avoided energy rates. The different definitions  
16             between Options A and B allow QFs to choose the definition that produces the

1 most revenues for the QF relative to their operations. While this is beneficial  
2 to the QF, the particular issue leads to an overstatement of the actual avoided  
3 energy benefit since each QF picked its option based on revenue optimization  
4 rather than a consistent definition of peak hours based on the Companies'  
5 avoided energy cost. The Companies recommend that Option A be  
6 eliminated, with Option B being the singular consistent definition of peak  
7 hours for avoided energy purposes.

8 **V. TARIFF ELIGIBILITY LIMITS**

9 **Q. DO THE COMPANIES PROPOSE SPECIFIC ADJUSTMENTS TO**  
10 **THE CURRENT ELIGIBILITY LIMITS FOR THE QF TARIFF?**

11 A. Yes, the Companies recommend the current tariff eligibility limit of 5MW be  
12 revised to 100kW.

13 **Q. WHAT IS THE RATIONALE FOR THIS PROPOSED REDUCTION?**

14 A. Witness Bowman speaks to the policy reasons for this recommended change  
15 in her testimony. In addition, there are also resource planning and equitable  
16 pricing justifications for this recommended change.

17 **Q. PLEASE EXPLAIN WHAT RESOURCE PLANNING ISSUES LEAD**  
18 **TO THIS RECOMMENDED CHANGE IN TARIFF ELIGIBILITY.**

19 A. From a resource planning perspective, both the need for a resource and the  
20 relative economic value of a resource changes over time. Time sensitive  
21 variables, such as fuel prices, load forecasts, economic conditions, technology  
22 efficiencies, environmental regulations, level of QF participation, among other  
23 factors, all impact the need for any given type of resource as well as the

1 economic value of the resource. As such, a tariff that is only updated every  
2 two years is not dynamic enough to value large amounts of QF capacity  
3 accurately.

4 **Q. WHY IS THIS MORE OF AN ISSUE NOW THAN IT HAS BEEN IN**  
5 **PAST YEARS?**

6 A. The culmination of the compliance requirements of NCREPS, the impact of  
7 state and federal tax incentives, and declining solar prices have resulted in a  
8 large solar QF development effort in NC. Approximately 1,000 MWs of  
9 potential solar projects currently fall in the 100 kW to 5 MW range. Under  
10 the current fixed tariff structure, all 1,000 MWs receive the same price signal  
11 which overstates the cumulative value created if all 1,000 MWs were to come  
12 to fruition.

13 **Q. PLEASE EXPLAIN WHY IT IS NOT APPROPRIATE TO SEND THE**  
14 **SAME PRICE SIGNAL TO ALL QFS.**

15 A. In addition to changing market conditions over the two year period in which  
16 standard avoided cost tariff rates are fixed, the sheer amount of QF interest  
17 changes the economic value from the 1<sup>st</sup> MW of QF capacity to the 1,000<sup>th</sup>  
18 MW of QF capacity. Holding all other variables constant, each block of solar  
19 that comes online diminishes the value created from the next block of solar.  
20 From an energy perspective, since solar resources have very similar output  
21 profiles they tend to reduce traditional utility generation in the same daylight  
22 hours. The first blocks of solar reduce the most expensive units, while the

1 next blocks reduce less expensive units. Once again, consider the following  
2 simple example from earlier in my testimony.

Unit Variable Costs Per Hour (\$ per MWh) Illustrative Only					
Hour ----- Load -----	Hour 1 30MW	Hour 2 40MW	Hour 3 50MW	Hour 4 50MW	Hour 5 40MW
Resources Online					
F-Frame CT (10 MW)			\$55	\$55	
Coal (10 MW)		\$42	\$42	\$42	\$42
Combined Cycle (10 MW)	\$35	\$35	\$35	\$35	\$35
Nuclear (10 MW)	\$8	\$8	\$8	\$8	\$8
Hydro (10 MW)	\$2	\$2	\$2	\$2	\$2
Average Fuel Cost (\$/MWh)	\$15.00	\$21.75	\$28.40	\$28.40	\$21.75
Marginal Fuel Cost (\$/MWh)	\$35.00	\$42.00	\$55.00	\$55.00	\$42.00

3  
4 For illustrative purposes only consider Hours 3 & 4 in the table above.  
5 The first 10 MWs of solar on this system would avoid \$55/MWh marginal  
6 energy. The next block of 10 MWs would avoid \$42/MWh marginal energy.  
7 The third block of 10MWs would avoid \$35/MWh and so on, and so forth.  
8 As this simple illustration shows, it is not appropriate to send a \$55/MWh  
9 price single to all 30 MWs of solar QFs. From a capacity perspective, the

1 same issue arises. In the example above, capacity was originally needed for  
2 the peak in Hours 3 and 4, but as solar penetration rises, the need for  
3 traditional capacity shifts to other hours. Hence both the avoided energy and  
4 capacity value created by solar QFs changes with increasing levels of solar  
5 adoption. In past years when QF interest was minimal, this impact was not an  
6 issue. However, given the current level of expressed QF interest, it is no  
7 longer appropriate to offer the same avoided cost rate to such a large quantity  
8 of QF providers as it results in paying above avoided cost in the aggregate.  
9 Moving the tariff eligibility limit from 5MW to 100kW will allow the  
10 Company to send the appropriate price signal through individual price  
11 offerings to QFs above 100kW.

## 12 VI. CONCLUSION

13 **Q. DO THE COMPANIES' RECOMMENDATIONS RELATING TO THE**  
14 **CALCULATION OF AVOIDED COSTS PROVIDE FOR A MORE**  
15 **FAIR AND ACCURATE CALCULATION OF SUCH COSTS?**

16 **A.** Yes, they do. The peaker methodology, implemented with the proposed  
17 adjustments outlined in my testimony relating to both avoided capacity and  
18 avoided energy, will provide a more accurate representation of the  
19 Companies' avoided costs. Specifically, by accounting for the relative need  
20 of the Companies for incremental generating capacity and by reducing the  
21 PAF to reflect the availability of the actual units being avoided, and by  
22 establishing hours over which capacity credits should be paid (based on the  
23 actual need of the Companies), the standard tariff rates will more fairly and

1 accurately reflect the actual capacity value being delivered by a QF to the  
2 utility. Similarly, by adjusting avoided energy values to reflect actual  
3 integration costs for solar PV generation, capping avoided energy benefits at  
4 the production cost of the avoidable CT unit, and eliminating optional tariff  
5 schedules with differential pricing not tied to the utility's avoided costs, the  
6 tariff rates will also more closely reflect the avoided energy benefits being  
7 delivered to the Companies' customers.

8 **Q. ARE THE COMPANIES' RECOMMENDED ADJUSTMENTS**  
9 **INTENDED TO UPDATE THIS METHODOLOGY TO REFLECT**  
10 **THE ACTUAL VALUE BEING DELIVERED BY QFS TO THE**  
11 **UTILITIES?**

12 A. Yes, the proposed adjustments to the calculation methodology are intended to  
13 do just that. In this way, the Companies will send appropriate price signals to  
14 QFs and compensate them accordingly for delivering capacity and energy of  
15 critical value to the Companies. The result is that the appropriate pricing will  
16 only incur costs to customers that relate to the actual benefit being provided to  
17 them.

18 **Q. WILL THESE RECOMMENDED ADJUSTMENTS MORE**  
19 **ACCURATELY REFLECT CHANGES IN THE MARKETPLACE**  
20 **SINCE SOME OF THE LEGACY COMPONENTS, LIKE THE PAF,**  
21 **WERE INSTITUTED?**

22 A. Yes, they will. It has been decades since many aspects of the Companies'  
23 standard avoided cost tariffs were originally established, and the marketplace

1 for QF resources has changed entirely since that time, particularly over the  
2 past several years. The Companies' proposed changes are intended to update  
3 these tariffs to bring them more in line with the current realities and dynamics  
4 of that marketplace.

5 **Q. WILL THE RECOMMENDED CHANGES RESULT IN STANDARD**  
6 **TARIFFS THAT MORE FAIRLY BALANCE THE REQUIREMENTS**  
7 **OF PURPA WITH THE INTERESTS OF THE COMPANIES'**  
8 **CUSTOMERS?**

9 A. We believe they will. From the Companies' perspective, the appropriate  
10 implementation of PURPA is a two-sided endeavor that must balance the  
11 rights of QFs under the law with the requirement that customers only be  
12 forced to pay just and reasonable rates for the power being provided to the  
13 utility, that in no event exceeds the utility's avoided costs.

14 **Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

15 A. Yes, it does.





# Duke Energy Photovoltaic Integration Study: Carolinas Service Areas

S Lu  
N Samaan  
D Meng  
F Chassin  
Y Zhang  
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M Warwick  
J Fuller  
R Diao  
T Nguyen  
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March 2014



*Proudly Operated by* **Battelle** *Since 1965*

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With important contributions from Power Costs, Inc., Clean Power Research, Alstom, and Duke Energy

March 2014

Prepared for Duke Energy

Pacific Northwest National Laboratory  
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## Acknowledgments

Research for this report involved collaborations among several firms and major contributors, including Pacific Northwest National Laboratory (PNNL), Power Costs, Inc. (PCI), Clean Power Research (CPR), Alstom, and Duke Energy. PNNL and PCI performed the generation impact analysis with photovoltaic (PV) data simulated by CPR. Duke Energy conducted the transmission simulations, and Alstom modeled the distribution effects. PNNL verified all simulation results, performed the analyses, and compiled information from the collaborators into this report.

Shuai Lu coordinated the study efforts at PNNL, and compiled the report with help from Mike Warwick. Shuai Lu also led the generation impact analysis and authored the generation section of the report, with significant contributions from Da Meng regarding ESIOs development, Ruisheng Diao and Chunlian Jin regarding reserve requirements, Forrest Chassin and Tony Nguyen regarding simulations using ESIOs and cost analyses, and Yu Zhang for graphic analyses of variability. Nader Samaan led the transmission analysis with contributions from Bharat Vyakaranam, and wrote the transmission study. Jason Fuller led the distribution analysis and wrote the distribution report. Mark Osborn and Marcelo Elizondo provided valuable comments to the draft report. The PNNL team was guided by Landis Kannberg.

Buck Feng and Nate Finucane from PCI performed GenTrader simulations and contributed to the methodology development for the generation study. Ben Norris and Skip Dise of CPR were primarily responsible for providing PV data. Ethan Boardman from Alstom worked with Duke Energy to develop the solution approach for distribution modeling and championed the project internal to Alstom. Jesse Gantz from Alstom was responsible for the distribution project deliverables, performed the model enhancements, simulations runs, and validation of data for the distribution study.

The study was not possible without the cooperation and individual contributions of many engineers and analysts from various departments at Duke Energy. They provided data and valuable insights throughout the study as well as a critical review of this report.

In addition, the authors would like to acknowledge comments and suggestions received on the draft report from the review panel coordinated by Aidan Tuohy from the Electric Power Research Institute. The panel includes the following colleagues:

- Electric Power Research Institute: Aidan Tuohy, Jeff Smith, and Mahendra Patel
- Utility Variable-Generation Integration Group: Charlie Smith
- Clemson University: Elham Makram
- Arizona Public Services: Jihad Zaghloul, Tony Tewelis, and David Narang.

The report is edited by Cary Counts at PNNL.

# Executive Summary

## Overview

Solar energy collected using photovoltaic (PV) technology is a clean and renewable energy source offering multiple benefits to the electric utility industry and its customers. These benefits include cost predictability, reduced emissions, loss reduction by distributed installations, and others. Renewable energy goals established in North Carolina Senate Bill 3 (SB3), in combination with the state tax credit and decreases in the cost of PV panels, have resulted in rapid solar power penetration within the Carolinas services areas of Duke Energy. Continued decreases in PV prices are expected to lead to greater PV penetration rates than currently required in SB3.

Despite the potential benefits, PV generation is variable in nature with limited predictability. Significant penetration of PV energy is of concern to the utility industry because of its potential impact on operating reliability and integration cost to customers, and equally important, how any additional costs may be allocated to different customer groups. Some of these impacts might become limiting factors for PV energy, especially growing distributed generation installed at customer sites.

Recognizing the importance of renewable energy developments for a sustainable energy future and economic growth, Duke Energy has commissioned this study to simulate the effects of high-PV penetration rates and to initiate the process of quantifying the impacts. The objective of the study is to inform resource plans, guide operation improvements, and drive technology and infrastructure investments for a steady and smooth transition to a new energy mix that provides optimal values to customers.

## Study Team

The study team consists of experts from Pacific Northwest National Laboratory (PNNL), Power Costs, Inc. (PCI), Clean Power Research (CPR), Alstom, and Duke Energy. PNNL, PCI, and CPR performed the study on generation impacts; Duke Energy modeled the transmission cases; and distribution simulations were conducted by Alstom. PNNL analyzed the results from each work stream and produced the report.

## Study Scope and Methods

The goal of this study was to determine, for the Duke Energy service areas in the Carolinas, the impacts of solar PV on ancillary services and generation production cost, as well as voltage, power flows, and losses in the transmission and distribution systems.

Rather than adopt a more intensive approach that would take several years, this study attempts to produce results in a timely manner using available data and analytic tools, to identify areas of concern, measure the degree of impact, and provide guidance for further actions. Accordingly, the study was limited to energy production cost modeling and steady-state, power flow simulations. Potential PV impacts on system dynamic characteristics, such as frequency response and dynamic and transient stabilities, were not included the study scope.

Three scenarios were simulated in the generation study: 1) compliance solely with the goals and schedules of SB3, 2) modest increases over SB3 goals, and 3) more rapid penetration of PV.<sup>1</sup> Generation impacts, including reserve requirements, control performance, and production costs were evaluated with projections every other year from 2014 to 2022 (Table ES.1). Figure ES.1 shows the locations of the projected PV sites. The PV penetration evaluated ranged from 673 MW<sup>2</sup> to 6800 MW (2% to 20% of peak load). To provide corresponding inputs to energy production cost modeling, system variability and reserve requirements were analyzed for each case. Of the two steps in energy production cost modeling, generation commitment and dispatch was performed for the Duke Energy system as a whole, while balancing operations were modeled individually for its component balancing authorities (BA) areas (i.e., Duke Energy Carolinas [DEC] and Duke Energy Progress [DEP]).<sup>3</sup>

**Table ES.1.** PV Penetration Cases

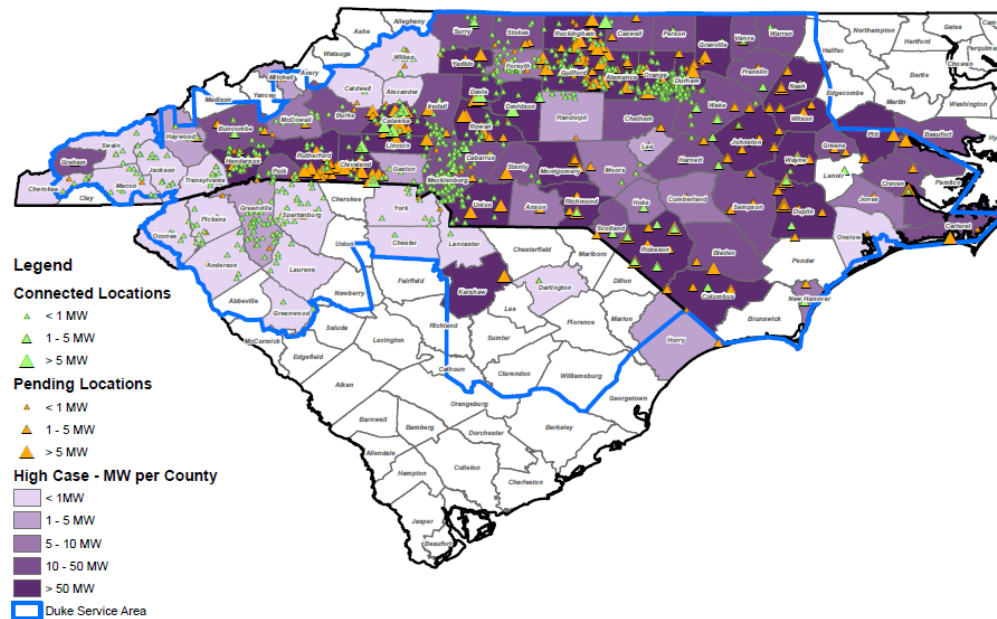
(MWac)	2014	2016	2018	2020	2022
Compliance					
DEC	361	631	785	1,012	1,197
DEP	312	312	334	395	483
Mid					
DEC	431	816	1,393	2,006	2,598
DEP	331	506	867	1,248	1,642
Smooth High	2.5%	5%	10%	15%	20%
DEC	500	1,000	2,000	3,000	4,000
DEP	350	700	1,400	2,100	2,000

Where applicable, the study relied on existing Duke Energy tools, data, and integrated resource planning assumptions. In addition, new modeling capabilities in both PV production and balancing authority operations were employed to capture the impact of PV variability up to 1-minute time scale. Resources including generators, pumped storage, demand-response, and long-term contracts were considered in the models. Load, resources, and fuel prices forecasts were consistent with Duke Energy integrated resource planning. The resource plans were developed according to projected load growth and PV installations in the compliance scenario. Therefore, the resource mix may vary from year to year, but stays constant for different PV penetration scenarios in the same study year. Data was provided by Duke Energy when available; otherwise it was simulated by the analysis team.

<sup>1</sup> Based on data from the interconnection queue, the level of actual penetration in the system may exceed compliance level, and is more close to the penetration level in the mid case.

<sup>2</sup> PV installation capacity in this document refers to alternating current (AC) capacity by default, unless noted otherwise.

<sup>3</sup> This treatment reflects the way Duke Energy system operates at the time of the study. Combining the two BAs or coordinating their balancing operations could potentially reduce the challenges from variable resources on generation operations, and is a subject for further studies and opportunity for operation improvement.



**Figure ES.1.** Locations of Projected PV Sites

Transmission analyses were conducted using “snapshots” of critical day types for each season, such as summer peak day.<sup>1</sup> The models were developed based on transmission planning cases of Duke Energy, and included 1197 MW of installed PV. The PV power output was determined from seasonal average of existing PV systems at times of the snapshots. Other PV penetration rates were not studied due to time constraints. All PV sources were assumed to operate at lagging power factors of 0.97; that is, they supply reactive power that is 25 percent of their real power output.<sup>2,3</sup> Transmission system voltage profiles and losses were compared between the cases with and without PV.

The same PV penetration and locations as used in the transmission analysis were assumed for the distribution study. Project PV installations were added to the DEC distribution system model taken from the Distribution Management System (DMS). Sequential power flow simulations with 30-minute intervals were performed on the entire DEC distribution system, and 3-minute interval simulations were conducted on one feeder as a case study to understand the impacts of variable PV output on feeder voltages, power flows, voltage control device operations, and system losses.

Duke Energy plans to incorporate the modeling tools that were developed during this integration study into its planning and operations tool kit and will continue to refine the approach and input as additional PV energy enters its system.

<sup>1</sup> This is consistent with current transmission planning and analysis procedures at Duke Energy and most other utilities. However, the “snapshot” approach is inadequate for PV impact analysis due to the variable nature of PV production and is an aspect for future improvements.

<sup>2</sup> This power factor is chosen based on historical measurements of selected PV sites in the DEC system. Interconnection requirements for North Carolina allow power factor to range between 0.95 lagging to 0.95 leading.

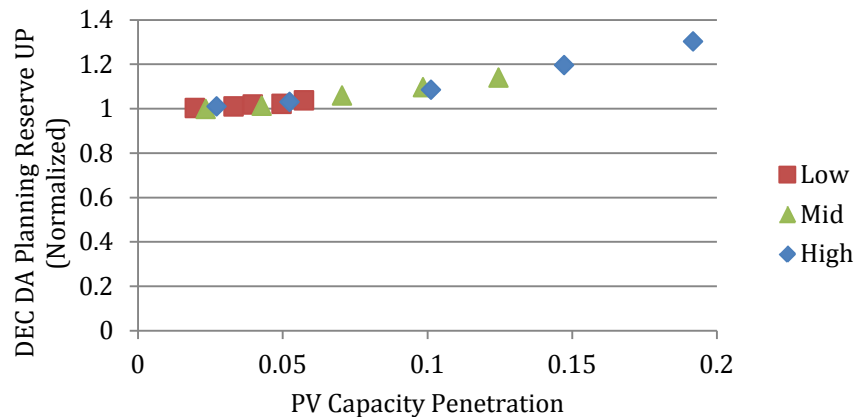
<sup>3</sup> Smart inverters with voltage control capability can vary reactive power output as needed for voltage regulation but have not been widely adopted in the distribution system, and therefore, was not considered in the study.

## Findings and Conclusions

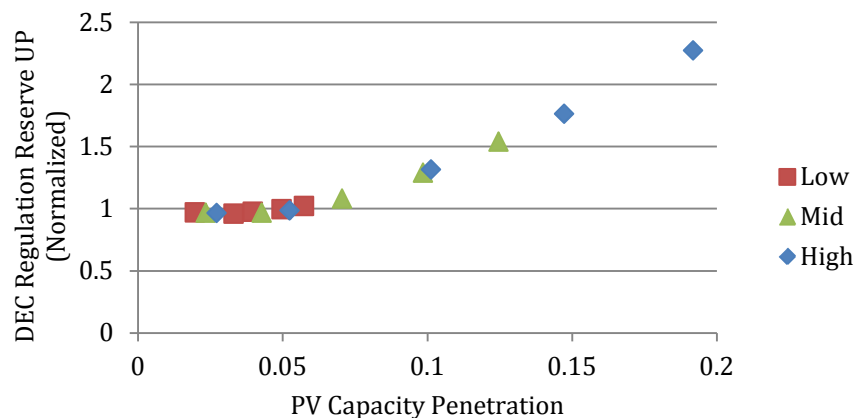
The study was performed with a set of assumptions, including projected PV installations, future load growth, resource mix, and fuel prices. Current Duke Energy operation practices were followed where appropriate, and present transmission and distribution system configurations and control methods were modeled in the simulations. The study has made the following findings and conclusions under the above context.

### Generation

The study found that system net load (load minus PV production) variability increases with PV penetration. As a result, with PV penetration increasing to 20 percent of peak load in the integration cases, system day-ahead (DA) planning reserve requirements (contingency reserve excluded) increase 30 percent compared to the values without PV (reference cases), and regulation reserve requirements increase 140 percent. These reserves are capacity from conventional generators to cover forecast uncertainty and variability of the system. The trend of reserve requirements are depicted in Figures ES.2 and ES.3 using the DEC system as an example.



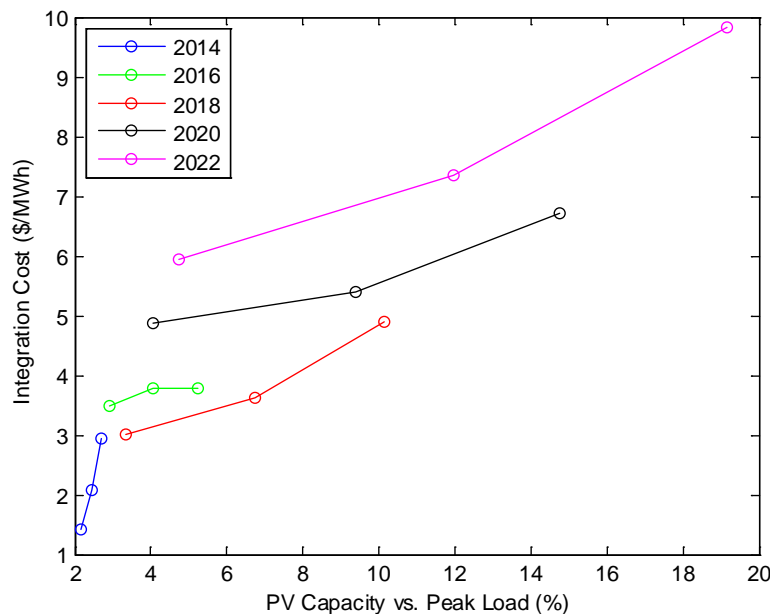
**Figure ES.2.** Day-Ahead Planning Reserve Up of All DEC PV Cases. Shown as the ratio between the requirements of PV case and corresponding reference case.



**Figure ES.3.** Regulation Reserve Up of All DEC PV Cases. Shown as the ratio between the requirements of PV case and corresponding reference case.

The Duke Energy system was able to maintain reliable operations in dispatch simulations, evaluated in terms of meeting ancillary service requirements and the target compliance level with North American Electric Reliability Corporation Control Performance Standards, with the caveat that contingencies were not modeled and contingency reserve requirement was assumed not affected by PV. Under the study conditions, Duke Energy's generation fleet proved capable of accommodating PV with an installation capacity of up to 6800 MW, or 20 percent of peak load, the highest level investigated in this study.

PV integration imposes additional costs on Duke Energy's current and planned conventional generating fleet, resulting from the need of additional reserves and cycling of conventional generators to compensate for PV variability. Although total system production cost decreases at higher PV penetration rates (when the cost of PV energy excluded), the unit cost for conventional generation to serve the same amount of energy increases with each increase in PV energy. Based on the load, resources, fuel prices and other assumptions made in the study, PV incurs an integration cost that ranges from \$1.43 to \$9.82 per megawatt-hour (MWh) of PV energy (Figure ES.4) in comparison with reference generation. The results show increasing unit PV integration cost at successively higher PV levels, which is consistent with other similar studies [3][4].



**Figure ES.4.** PV Integration Cost as a Fraction of PV Capacity to Peak Load (MW)<sup>1</sup>

## Transmission

As modeled, PV supplies both real and reactive power resulting in an increase in voltage magnitude proportional to the amount of PV output at sub-transmission buses where the distributed energy from PV

<sup>1</sup> Main factors affecting PV integration cost include resource mix and fuel prices, besides PV penetration and peak load. In the Integrated Resource Plan (IRP) used for the study, 2014 and 2016 cases have the same resource mix, while more efficient combined cycle and peaking units are added to later cases. This contribute to the result that 2016 cases show higher integration costs than those of 2018, but are more in line with the trend shown by 2014 cases. Difference in PV integration cost in years 2018 to 2022 results should be attributable to both increases in fuel price forecasts and changes in resource mixes.

sources is aggregated. The most affected areas in the Duke Energy system are in the 44-kV systems where voltage magnitude violated the upper limit in the spring and fall cases during light-load conditions. Voltage control devices modeled in the transmission system appeared not being able to handle this over-voltage issue, which suggests mitigation procedures should be investigated further.

The amount of energy loss reduction in the transmission network due to distributed PV depends on many factors such as the type of the conductors in the system, PV real power outputs and associated power factor, and the nature of load. For the four power flow snapshots analyzed, transmission loss reduction due to PV (i.e., difference in losses between the PV case and the case without PV) were between 2.6 and 5.7 percent as a percentage of PV output. As PV output and other system conditions change, the amount of loss reduction is expected to change, too. Analysis over a long time period (preferably one year or more) is needed to get a reliable assessment on the total loss reduction.

## **Distribution**

The addition of PV along distribution feeders was observed to provide both costs and benefits. The study here attempted to determine general trends of them, rather than quantify specific values.

During higher load periods, typically in the summer, both real and reactive losses decreased. During lower load periods, both real and reactive losses tended to increase. On average, feeders show a reduction in losses due to the addition of solar distributed generation, particularly in the summer season. Spring and fall indicate negligible changes in losses. Meanwhile, there is a wide range in the individual feeder results. Any net benefit is dependent on feeder topology, PV penetration level, and interconnection point.

In the simulation, equipment overloads tended to decrease due to the offset of local power flow by local generation, but in a few cases additional overloads were experienced mainly due to reverse power flows. In a few cases, substation power factor was negatively impacted; this may require evaluation of current capacitor settings, re-evaluation of solar installations' reactive power requirements, and in the future, perhaps the coordinated use of smart inverter technology by solar installers.

Feeders servicing PV installations experienced greater voltage fluctuations, and consequently, more control actions by voltage regulation devices. Increased regulator operations in turn reduce asset life. However, the severity or how quickly any individual PV site impacts the regulator life, depends on where the PV installation is located, its relative size, and the load on the circuit, among other factors.

## **Discussion**

### **Generation**

It should be noted that projected PV system sizes and locations, future load growth, resource mix and fuel prices, are a few assumptions that have great impact on study results. Although they were carefully made with the best data available, future system conditions will be different. The sensitivity of PV integration cost to PV locations, fuel prices, and thermal generation build-out should be investigated, in addition to the defined scenarios, to fully understand the impact of these assumptions on study results.

Of similar importance to the above assumptions are the simulation models and their parameters, such as PV production, DA and real-time forecasts, unit commitment and economic dispatch, automatic

generation control and operator actions. New study tools and procedures to model PV production and system operations were applied in the study. In some places necessary simplifications were made to produce the results timely, while in other cases reasonable improvements to operation procedure were modeled to deal with high-PV penetration rates.

For example, PV fleet forecasts for DEC and DEP in DA and real time were incorporated in reserve requirements calculations, which do not yet exist in real practice. Unit commitment was performed using actual load and PV production, instead of forecasted values as what happens in reality. Dynamic operating reserves that vary with hour of the day were applied in the unit commitment process. These models and parameters should be checked against real-world data for effectiveness as operation experience at significant PV penetration rates is accumulated over time.

In summary, refined model assumptions, additional validation of modeling tools, and improved study procedure should be attempted in future studies. Contingencies caused by conventional resources and affected by PV systems should be considered. Frequency response of the system at high-PV penetration rate, which was left out of the scope of this study, should also be investigated.

The same set of assumptions and models which affect study results significantly also point to the directions of operation and technology improvements for a smooth transition toward the high-PV energy mix. The improvements can be categorized into the following aspects:

1. *Increase Fleet Flexibility* – More flexible and efficient fleet tends to have a lower PV integration cost and better control performance, which should be taken into consideration in new generation build-out. Storage and demand response are other effective approaches to meet such goals. Fleet flexibility can also be improved by coordinating the balancing operations of DEC and DEP.
2. *Reduce Uncertainty and Variability* – Incorporating PV forecast into operation processes and improving forecast accuracy can directly reduce operation uncertainty. Aggregation of PV production in the two areas through BA coordination increases diversity and reduces total reserve requirements, which further helps lowering PV integration cost. Research is ongoing to reduce additional reserve requirements induced by PV variability through controlling power production ramp rate and providing regulation service by PV inverters.

Efforts to make the above improvements are certainly not free. Nonetheless, the attempts should be worthy if their costs are a fraction of the potential PV integration costs. These improvement solutions need to be assessed through future studies.

## Transmission

The transmission analysis is preliminary because of the seasonal day “snapshots” approach and assumptions made about PV inverter and transmission system voltage control capability to manage reactive power. Impacts on transmission on other days or over multiple day periods may have different impacts than identified here. Improvement on the coordination of the transmission voltage control devices, such as capacitor banks and inductors, could be made to alleviate the over-voltage issues with PV. Similarly, advanced inverters on the market are able to mitigate some of the reactive power impacts identified. Although those have yet to be deployed in the Duke Energy area, if these are adopted as either

an interconnection requirement or industry standard, the reactive power impacts noted here will be very different. These are several topics that should be researched further.

### **Distribution**

Mostly qualitative observations were made considering the limitations of the study approach, including low time resolution in the DEC system-wide study and short simulation time period in the intermittency study on the selected feeder. In the future, both overloads and reactive power requirements should be addressed through interconnection studies. If it becomes necessary for interconnection studies to thoroughly assess the economic benefits and impacts (beyond safety and reliability), it is expected that interconnection costs and time of delivery will increase and new tools may be needed.

The impacts noted will also result from a critical mass of customer-sited PV systems, although small systems typically do not require interconnection studies. These systems are the cause of widely noted distribution circuit level concerns among Hawaiian utilities, which currently experience much higher small PV system penetration rates than in this study. The present study was too limited to evaluate the distribution and magnitude of these concerns as an issue. Additional research may be warranted to assess the need for modification of interconnection procedures, incentives, and rate treatment for small systems.

## Acronyms/Abbreviations

ACE	area control error
AGC	automatic generation control
CC	combined cycle
CI	clearness index
CPR	Clean Power Research, Inc.
CPS	Control Performance Standard
CT	combustion turbine
DA	day-ahead
DR	demand response
DEC	balancing authority of historical Duke Energy Carolinas system
DEP	balancing authority of historical Progress Energy Carolinas system
DER	distributed energy resources, such as distributed solar PV, combined heat and power and storage
DG	distributed generation
DMS	Distribution Management System
DOTS	Distribution Operator Training Simulator
ESIOS	Electric System Intra-hour Operation Simulator
IRP	integrated resource plan
ISO	Independent System Operator
O&M	operating and maintenance
NERC	North American Electric Reliability Corporation
PCI	Power Costs, Inc.
PNNL	Pacific Northwest National Laboratory
PS	pumped storage
PV	photovoltaic
RPS	renewable portfolio standard
RR	regulation reserve
RTD	real-time dispatch
SCADA	supervisory control and data acquisition
TND	truncated normal distribution
VG	variable renewable generation

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## 1.0 Introduction

### 1.1 Background

North Carolina Senate Bill 3 (SB3) established renewable energy goals for the state's utilities, including the Carolinas service areas of Duke Energy, starting at 3 percent in 2012 and leveling off at 12.5 percent in 2021. The bill encouraged utilities to meet this goal using energy from a variety of renewable resources and other measures. To date, solar photovoltaic (PV) projects have dominated Duke Energy's efforts to comply with the requirements of SB3.

Recent and expected continued decreases in the cost of PV projects, coupled with a 35 percent state tax credit for PV installations are undoubtedly behind this trend. In addition to the PV that is entering the system in response to SB3 requirements, a significant amount of qualified facilities are entering the system simply leveraging the favorable incentives in North Carolina, primarily the tax credit. At the time of this analysis Duke Energy had over 2000 MW of PV projects in its interconnection queue.

PV generation provides sustainable energy at a predictable price. Along with other potential benefits, such as reduced transmission and distribution losses [1][2], PV can become an important future utility resource. However, over-reliance on one type of resource that is variable and cannot be dispatched, can present operational challenges costly to manage. In addition, PV projects are typically much smaller and less constrained by location than conventional generators. This may lead to clustering of projects at locations that create reliability concerns.

Existing studies suggest too high or too rapid penetration of PV capacity could affect utilities' ability to maintain levels of reliability and the reasonable rates expected by ratepayers and other stakeholders [3][4][5], if no changes are made to the current power system. Both potential benefits and prospective costs of PV generation will vary from utility system to utility system, depending on penetration rates, resource mix, operation practice, PV system locations and other factors. The solar and utility industries are learning more from each other's concerns and addressing them with advanced inverters and control systems and smarter operation approaches for anticipating and managing daily, hourly, and real-time solar power production respectively.

This is a healthy situation, because continued decreases in the cost of solar PV systems suggest higher penetration rates in the future for all utilities, including Duke Energy, even in the absence of renewable mandates. Thus far, the Duke Energy system has been able to meet the goals of SB3 and accommodate the rapid addition of PV; its continued ability to do so while maintaining customer and regulator expectations for reliability and reasonable rates was the impetus for this study.

### 1.2 Objectives

The goal of this study was to determine, for Duke Energy service areas in the Carolinas, the impacts of solar PV generation on ancillary services and production cost of the conventional fleet on the generation side, and voltage, power flows, and losses in the transmission and distribution system. The study attempts to produce results in a timely manner using available data and analytic tools, to identify potential areas of concern, measure the degree of impact, and provide guidance for further actions, rather than undertake a more intensive and exhaustive study that could take several years. Accordingly, the

study was limited to production cost modeling and steady-state, power flow simulations using data and tools familiar to Duke Energy and supplemented by new tools and analytics from the study team. Potential PV impacts on system dynamic characteristics, including frequency response, dynamic and transient stabilities are not within the scope of this study. It is expected that findings from the study can be used to inform decisions establishing avoided cost rates for qualified facilities, PV interconnection requirements and to guide resource plans and future investment.

### 1.3 Methodology

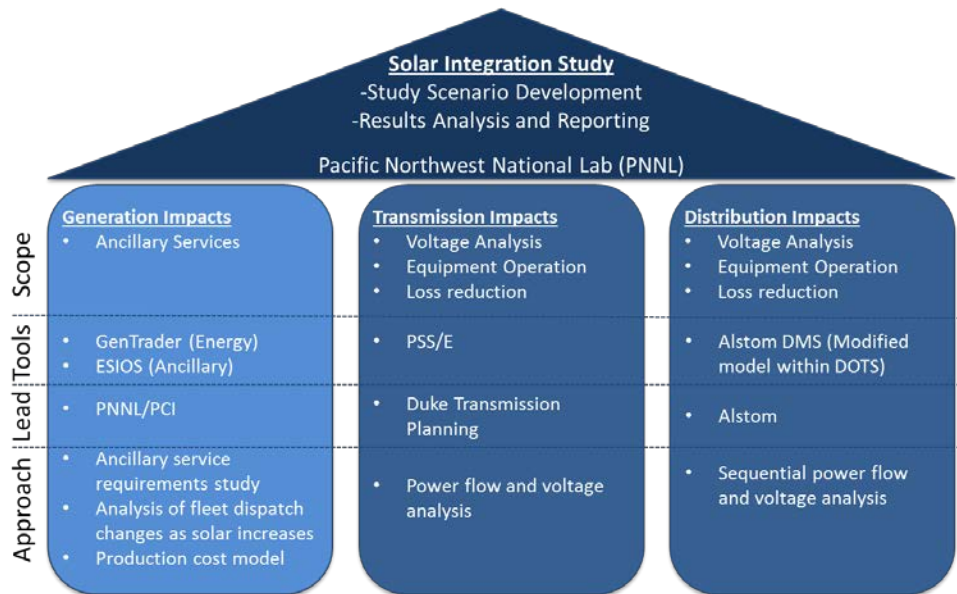
The benefits, costs, and “value” of PV have been assessed in a variety of forums including those for integrated resource planning (IRP), resource acquisition, rate-making, and avoided costs. Each of these forums has evolved to address a specific aspect of utility planning, operation, and rate setting along with similarly specialized analytic methods and tools. None of these methods provides a fully integrated evaluation capability extending from distribution through transmission to generation (and vice versa) or from minute-by-minute dispatch through typical ten to twenty year resource option analyses. This report describes an effort to approximate such an analysis so that results of distribution, transmission and generation analyses are internally consistent. In the absence of an all-encompassing modeling tool, several purpose-specific tools were used. This is a second-best solution, but it represents an improvement over other methods reviewed by the study team.

In the interest of time, analyses were divided along structural lines into tasks specific to generation, transmission, and distribution. Analysis of generation effects was performed by Pacific Northwest National Laboratory (PNNL) and Power Costs, Inc. (PCI), using GenTrader, Electric System Intra-Hour Operation Simulator (ESIOS) and information from the current IRP filings for the Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) systems. Transmission modeling cases were designed and conducted by the Duke Energy transmission planning team using PSS/E. Alstom, using their Solar DG (distributed generation) Modeler and Distribution Operator Training Simulator (DOTS), modeled the distribution effects. In both the transmission and distribution studies, PNNL verified the simulation results and developed the analysis results. Solar PV system performance was modeled by Clean Power Research (CPR). Duke Energy personnel provided data and other support, and made important contributions to the development of detailed study procedures. PNNL incorporated the results from each of these studies into this report. Figure 1.1 illustrates the structure of the study team and tasks.

GenTrader is a suite of software tools specialized in generation scheduling, available from PCI. The Fuels and System Optimization Group at Duke Energy currently uses GenTrader to create unit schedule and fuel-burn projections that are used to update rate filings in both North Carolina and South Carolina. ESIOS is a suite of tools developed by PNNL, with capability to model automatic generation control<sup>1</sup> (AGC) and operator dispatch actions. It is based on experience accumulated through years of analysis on wind and PV integration issues for several utilities and independent system operators (ISOs) [3], [6]-[10]. ESIOS is not a commercial product, but a research tool that continues to evolve. PSS/E is the tool developed by Siemens for power system analysis in the transmission system. A number of traditional planning and research-orientated simulation tools exist for addressing the impact of solar DG at the distribution level [21]. However, each of these tools has limitations, particularly in the availability of

<sup>1</sup> AGC is an automated mechanism for adjusting the power output of multiple generating resources of an electric power system, in response to instantaneous changes in the load.

models and data within Duke Energy's current work flow. Conversion and validation of models between tools can be costly and time consuming. Alstom's DOTS, which uses the same inputs and models as their Distribution Management System (DMS), was used because of the availability of the models for Duke Energy's distribution system. This allowed for a broader evaluation of feeders within the service territory.



**Figure 1.1.** Study Structure Overview

To analyze generation impacts, different approaches have been applied in existing work. Studies [1] and [2] both used an underlying assumption that the integration of renewables will only replace the marginal generator; therefore, the avoided energy cost can be calculated using the cost of the marginal generator or the marginal price of power in the market. This assumption is not true when PV penetration increases to the point where it will displace intermediate and base load generators and increase the cycling of them. Production cost simulation provides a more reliable approach to study the benefits and costs of integrating renewable generation. PV studies employing such an approach include the NV Energy study [3], the APS study [4], and the PJM wind and PV study [5]. This study uses a similar production cost simulation approach for integration cost assessment.

Conventional generating resource options were taken from the IRP filings. GenTrader was used to model unit commitment and hourly dispatch. ESIOS was used to model intra-hour dispatch. The results of both analyses were combined to include cost of base load generators and market transactions in GenTrader and of AGC, pumped storage and peaking units from ESIOS re-dispatch. CPR simulated the performance of solar systems representing every area in the Duke Energy system. This allowed for analysis of the distribution of PV as a generating resource anywhere, and potentially everywhere. Transmission analyses were conducted for four seasonal days as "snapshots." The use of selected days for case study is consistent with current transmission planning and analysis procedures at Duke and many other utilities. Hourly sequential power flow simulations were performed on the entire DEC distribution system and 3-minute interval simulations were conducted on one feeder as a case study to understand PV impacts on feeder voltages, power flows, voltage control device operations, and system losses. The distribution feeder case study is illustrative; it was not designed to be representative, as one feeder cannot

represent the necessary variety of feeder conditions and potential combinations of PV loading and interconnections along a feeder.

It should be noted that assumptions and simulation models and parameters directly affect the study results. Necessary simplifications were made to produce the results timely. Careful and reasonable adjustments to the operation model were made to deal with high PV penetration rates. However, to ensure results were sufficient to answer the critical questions, further studies are recommended later in the report for additional areas that should be addressed.

## **1.4 Organization of the Report**

The rest of this report is organized as follows. Chapters 2, 3, and 4 present the scope, methodology, data inputs, and results for generation, transmission, and distribution studies, respectively. Chapter 5 summarizes the findings and suggestions for further research, and reference citations are provided in Chapter 6. Each of these topics is summarized within the body of the report and more detailed information, tables, and charts consigned to the appendices to accommodate a wider range of readers with interest in this subject and these findings.

## 2.0 Generation Study

### 2.1 Scope

The generation study is one of three components of this report. It focused on quantifying the impacts of various levels of PV on ancillary service requirements and on system energy production costs in the Duke system. Energy production cost is based solely on the conventional generation fleet and does not include the cost of PV generation. PV energy and capacity are valued using the “peaker” method in Duke Energy’s avoided cost tariff, and thus is not included in this study. The DEC and DEP systems were studied as individual balancing authorities in the assessment of reserve requirements, intra-hour dispatch and control performance, while generation commitment and dispatch is modeled jointly, mimicking how Duke Energy currently operates.

### 2.2 Methodology

#### 2.2.1 Modeling Approach

Realistic PV production data that is weather synchronized with load is a critical input to the study. Synthetic PV output was produced based on the SolarAnywhere® FleetView™ modeling tool<sup>1</sup> for all study scenarios. Using locations and PV capacities of each scenario, the tool modeled PV production for each hour for a fixed system at each location. To account for variations in system configurations and anomalies such as inverter clipping, modeled PV data was calibrated against a set of utility-metered data. In addition, PV data with 1-minute resolution was created using a cloud motion vector method and calibrated in a similar fashion to the hourly data.

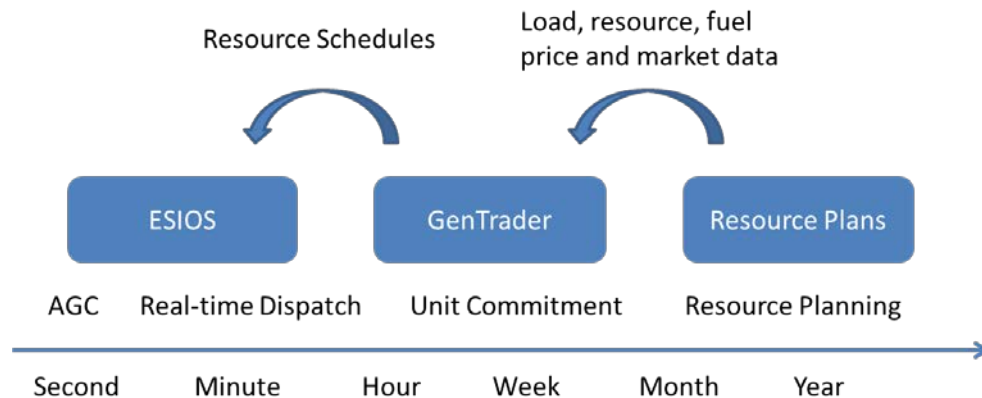
Duke Energy system day-ahead (DA) planning reserve and regulation reserve requirements were analyzed by modeling DA and real-time forecasts for PV and load. For simplicity, the term operating reserves is used when referring to both of DA planning and regulation reserves. Please note the DA planning reserve here should not be confused with the planning reserve margin in the IRP context. DA forecast errors and variability of PV and load from minutes to hours all contribute to the DA planning reserve requirements. Real-time forecast errors and variability of PV and load at the minute time scale determines regulation requirements. The contingency reserve requirement is a component of the Duke DA planning reserve, and is not assumed to change with PV.<sup>2</sup> Consequently it was excluded in the DA planning reserve calculations for this study.

<sup>1</sup> SolarAnywhere® is a database of solar irradiance derived from NOAA GOES East satellite-imagery and temperature. Using SolarAnywhere® PV production can be simulated from 1998 to the present to analyze historical variability and trends.

<sup>2</sup> According to current NERC Disturbance Control Performance Standard BAL-002-2, minimum contingency reserve requirement is determined based on a balancing authority’s Most Severe Single Contingency. PV systems are usually much smaller in capacity compared to conventional power plants, and therefore, will not affect contingency reserve requirement based on this standard. On the other hand, the possibility of suddenly losing a large amount of PV generation cannot be ruled out, due to weather or anti-islanding design of distributed PV responding to a system fault. The severance of this type of situation is subject to further investigation and outside the scope of this study.

Impacts of PV generation on energy production were analyzed by modeling Duke system generation commitment and dispatch. Because PV variability spans time scales from tens of seconds to months, energy production modeling uses 1-minute resolution and is performed for one year for each study case, to better capture the operational impacts of PV. Generator unit commitment and hourly dispatch were modeled by PCI using GenTrader. Different reserve requirements at various PV penetration rates were incorporated in the unit commitment process. A dynamic conventional generation fleet from the Duke Energy IRP is used for the study, which adjusts resource expansion plans according to expected load growth, energy efficiency programs, electric vehicles, etc., as well as projected PV installations in the compliance scenario. Therefore, the generation fleet varies from year to year, while staying constant for different PV penetration scenarios in the same year.

Intra-hour dispatch of generators connected to AGC, peaking units and pumped storage were simulated by PNNL using Electric System Intra-hour Operation Simulator (ESIOS), with schedules produced from GenTrader. Details about ESIOS dispatch approach can be found in [6] as well as in Appendix A. Control performance was assessed using North American Electric Reliability Corporation (NERC) Control Performance Standard 2 (CPS2)<sup>1</sup> for various PV penetration cases.<sup>2</sup> Adjustment of reserves and unit dispatch was performed when necessary to make sure the target performance range was achieved. PV integration cost<sup>3</sup> was then evaluated by comparison of energy production cost between PV cases and reference cases. Besides quantifying PV impacts on operating cost, the results can also provide system operators with more insights on what to expect with different amount of PV generation in the system. Generation study tools and the process used in this study are shown in Figure 2.1.



**Figure 2.1.** Generation Study Tools and Process

<sup>1</sup> The NERC CPS2 calculation is a NERC control performance measure designed to bound area control errors (ACE) 10-minute averages and to limit excessive unscheduled power flows that could result from large ACEs) [11].

<sup>2</sup> CPS2 was the main metric used by Duke Energy operations at the commissioning of the study, while the new metric balancing area ACE limit (BAAL) was still in field trial. Control performance could be evaluated using BAAL standard in the future if it replaces CPS2 in operations.

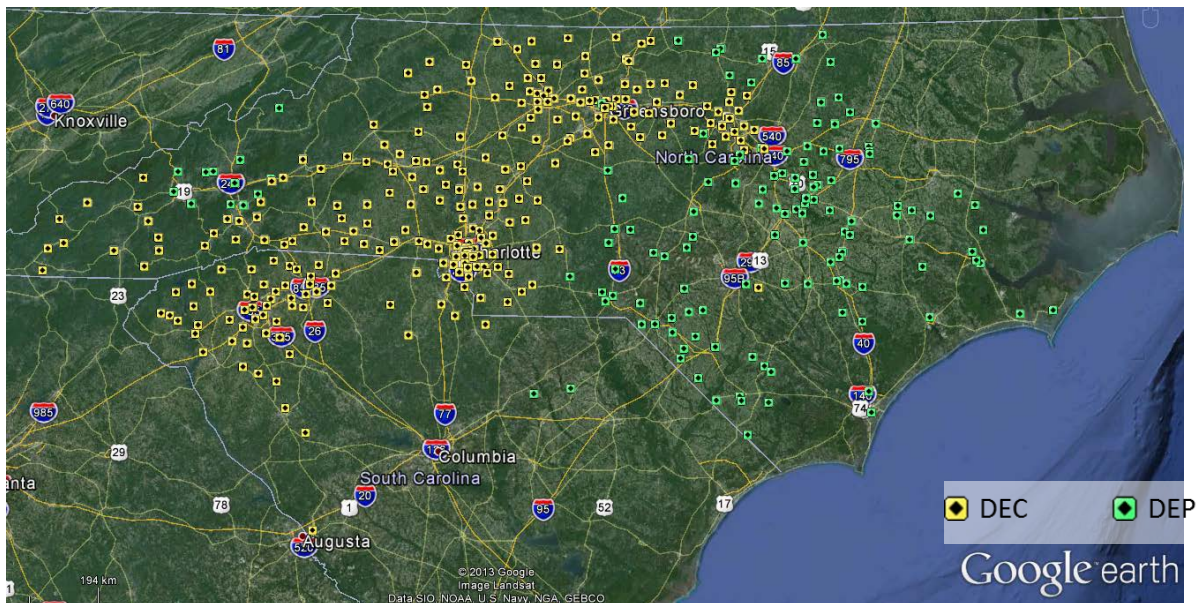
<sup>3</sup> The integration cost captured in the study comes from fuel efficiency loss, startups and O&M costs resulting from additional reserve requirements and dispatch of resources to match variable generation and load. The impact of wear and tear caused by generator startups and output adjustments is not considered.

## 2.2.2 PV Production Data

### 2.2.2.1 Overview

DukeEnergy provided a list of resource locations throughout the DEC and DEP systems. These include both sites of actual PV installations and zip codes where capacity is expected to be installed.

Figure 2.2 shows a map of the system locations. Yellow squares correspond to installations in DEC, while green squares correspond to those in DEP. There were 918 PV systems modeled for DEC and 290 modeled for DEP, for a total of 1208 systems. Hourly, normalized PV production data from the models was calibrated such that modeled aggregate production matched the aggregate output of a selected set of Duke Energy metered systems. This process was necessary to account for differences in design configurations. Calibration was performed separately for DEC and DEP.



**Figure 2.2.** Map of PV System Locations used in the Generation of PV Fleets

After modeling PV production and calibrating against measured fleet-level data, the modeled PV production was then scaled and aggregated to create hourly fleet production in time-series data sets corresponding to Duke Energy anticipated future-year PV penetration levels (Duke Energy provided the scaling factors). These scaling factors were used to create modeled fleet-level production time series for the DEC and DEP systems in 2014, 2016, 2018, 2020, and 2022 under three different PV growth scenarios.

Finally, CPR created high time-resolution data sets for use in the evaluation of ancillary services. This resulted in data for individual systems and fleet aggregations corresponding to 1-minute time steps with 1-km x 1-km spatial resolution.

### 2.2.2.2 PV Systems Data

In order to simulate the various levels of PV penetration, it was necessary to distribute PV across the sites identified by Duke in Figure 2.2. To do so, each location was geocoded. For locations identified by street address, the latitude and longitude of the address was determined. For locations identified by zip code, the zip code centroid was determined and latitude and longitude was taken for that location.<sup>1</sup> For each location, the corresponding “pixel” of SolarAnywhere® irradiance data was determined for modeling purposes.

Systems were defined as follows.<sup>2</sup> Each system was given a 1 kW-AC rating based on a 15 percent loss factor, a 95 percent load-weighted average inverter efficiency, and a 90 percent module de-rate factor. Systems were modeled as south-facing, fixed (non-tracking) with a 25 degree tilt angle, to maximize energy production. Most systems were identified by Duke Energy as “ground mounted,” in which case a row count of 12 and a relative row spacing value of 2.5 were used (typical values for systems about 1 MW in size).

The resulting time series corresponded to single PV systems with the above attributes. These time series were then modified by applying power-level scaling factors as described in Appendix A.

### 2.2.2.3 Solar Irradiance Data

Solar irradiance data is from SolarAnywhere®, and is available in one of three formats: standard, enhanced and high resolution. High resolution data was required for the creation of the 1-minute data sets. The high resolution data set is only available on a case-by-case basis. For this project, enhanced resolution irradiance data was created covering the rectangle that encompasses all points of interest. Then, the high resolution data was created using cloud motion vector methods. Figure 2.3 below shows satellite images of Charlotte, North Carolina, with 10-km and 1-km grids for comparison.



**Figure 2.3.** Satellite Images of Charlotte, North Carolina. The left image shows 10-km gridding while the right image shows 1-km gridding.

<sup>1</sup> All 918 DEC PV systems and 255 of 290 DEP PV systems used zip code center. An additional 32 DEP PV systems were located based on street address and 3 were located based on the center of the county they were in.

<sup>2</sup> Data sets were originally produced for systems with 35 degree tilt angle and not row shading. Based upon a Duke Energy review of this data against metered system data, the system specifications were modified as described here and the calibration method was implemented.

#### 2.2.2.4 PV Production Data Validation

To provide a check on the resulting data, capacity factors were calculated and inspected for each system. A sample PV system in the DEP area was also selected for detailed evaluation. The annual energy for the sample PV system when simulated with hourly data was 1933 kWh vs. 1900 kWh when simulated using 1-minute data (101.8 percent of the annual energy when simulated with 1-minute data). The minimum power for selected system was 0 kW, while the maximum power was 1.13kW.

The simulated PV data was also calibrated against the aggregated PV output from existing PV systems in the DEC and DEP service areas, respectively. Details can be found in Appendix A.

### 2.2.3 Quantifying PV Integration Cost

#### 2.2.3.1 Integration Cost Components

The variability and limited predictability associated with PV can cause the power system to incur additional costs, resulting from the need of carrying additional reserves and cycling of conventional generators to compensate PV variability. The following costs have been cited in existing renewable integration studies [3][4][20]:

1. Efficiency loss resulted from additional cycling (startups and adjustments in output to balance generation and load) of conventional generating units and the need for extra reserves to follow the additional variability and prepare for the uncertainty introduced by PV generation – Additional operating reserves, unit startups and more frequent up and down ramping movements are required, which causes additional fuel cost compared to the case of serving same amount of energy but with less cycling.
2. Increased capital and operating and maintenance (O&M) cost from cycling the conventional units – These include the generating unit startup cost, and additional wear and tear from cycling of the conventional units that may reduce the time interval between maintenances outages, increased unplanned outages, and reduced lifetime for mechanical parts, all of which results in incremental capital and O&M cost.
3. Energy curtailment (the cost to manage excess PV energy production) and other reliability impact mitigation approaches, whether operational or technological – PV production during off-peak periods can result in generation in excess of need. To restore load/resource balance excess energy may need to be exported at uneconomic prices (including negative prices), dispatch of generation out of merit (least cost) order, or disruption of transmission schedules. Too rapid change in PV production can outrun the response rate of thermal generators. Technical solutions such as increasing the operating range and ramp rate of generators and adoption of energy storage and demand response resources can be implemented to increase the flexibility of the fleet and avoid deterioration of control performance but at additional cost.
4. Capacity cost of increased operating reserve requirements – This includes the capital and operating costs of such reserves to meet the need of integrating PV energy, whether provided by the utility company's own fleet or acquired from the market; and potentially the lost opportunity to serve capacity and energy in the market if the reserves are self-provided.

It should be noted that integration of PV energy generally results in net reduction in total energy production cost measured by fuel, startup and O&M costs of the conventional fleet. It also reduces the capacity required from conventional generation to meet peak demand. These are the energy and capacity benefits of PV, or avoided costs by the utility. The integration cost components identified above occurs while accommodating PV energy and are physically inseparable from its benefits. Methodology has to be carefully designed to quantify such costs.

Among the above components, items 1 and 2 can be calculated from production cost simulations, and are the focus of the PV integration cost investigated in this study. Within item 2, impact of wear and tear on AGC units caused by more adjustments to balance generation and load was not considered due to the lack of data and time constraints.

Item 3 depends on the actual mitigation approaches needed and can be quantified by including mitigation solution models in the production cost runs. No such approaches were taken beyond the resources available in the Duke Energy system's IRPs used in the study. Therefore, item 3 is not specifically addressed in this study.

Item 4 can be calculated using the capacity cost of new resources, market price of reserve capacity, or the opportunity cost of providing these reserves with existing resources, after quantifying the incremental reserve requirements with PV. The investigation on this item is outside the scope of this study.

Table 2.1 summarizes the PV integration cost components discussed above and whether they are captured in this study.

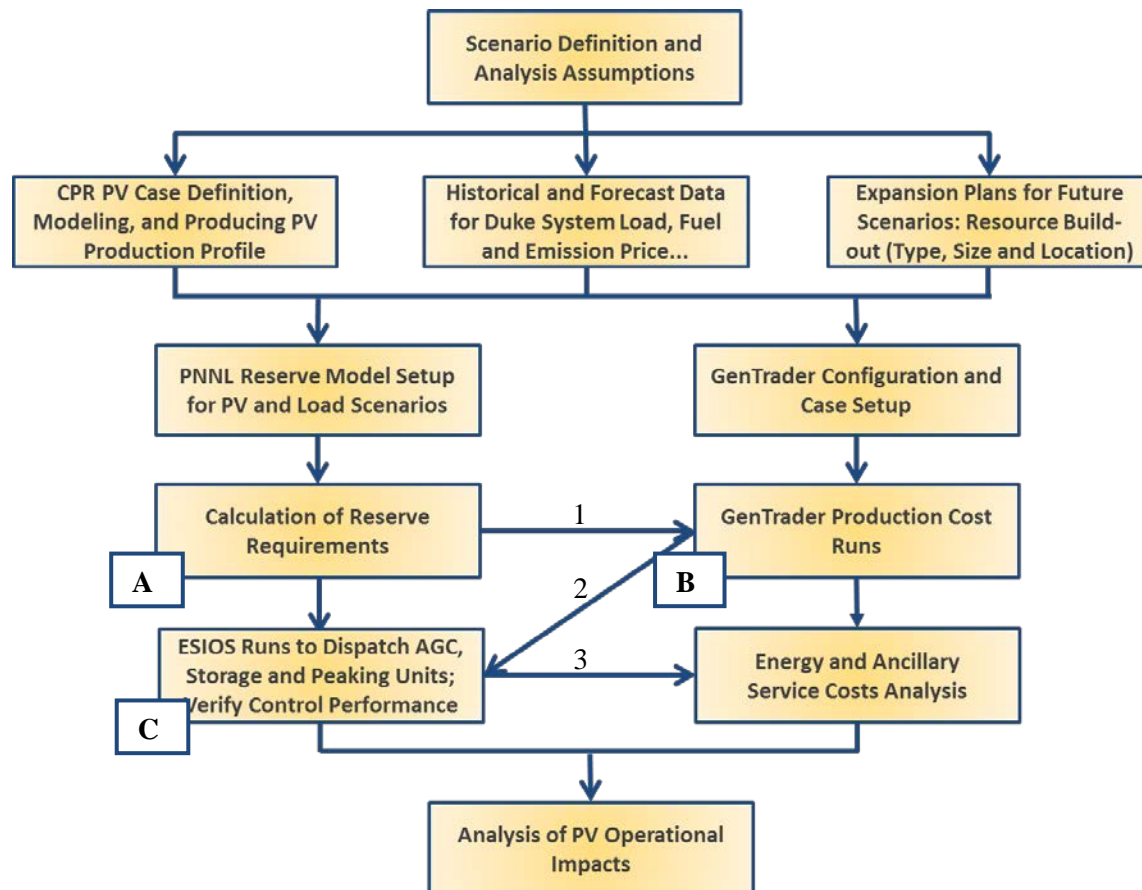
**Table 2.1.** PV Integration Cost Components

Cost Components	Fuel Efficiency Loss	Additional Capital and O&M Cost	Operational and Technological Improvements	Capacity Cost of Additional Operating Reserves
Causes	Carrying additional reserves;  More startups and more frequent output adjustments.	More startups;  Impact of wear and tear on maintenance cost and components lifetime.	Fast variations with PV production; Undispatchability and limited predictability of PV production.	Capital and operating cost of resources providing additional operating reserves.
Quantifying Approach	Production cost modeling	Production cost modeling	Production cost modeling with additional operational and technological solution models	Capacity cost of new resources or opportunity cost of existing resources in the market
Captured in the Study or Not	Yes	Partially (wear and tear not included)	No	No

### 2.2.3.2 Study Procedure

Figure 2.4 shows the flow of tasks in the generation study. Block A in Figure 2.4 determines the amount of DA planning reserves needed to cover forecast uncertainty at the unit commitment time horizon as well as the within-hour variability for both energy demand and PV energy production. Block A also determines the amount of regulating reserves to cover the minute-by-minute mismatch between generation and load. In this study, DA and real-time load and PV forecast models were constructed to include the impact of forecast uncertainty. Alternatively, perfect load and PV forecasts can be assumed in Block A to remove the impact from forecast errors so that the reserve requirements only count for load and PV variability. The approach to derive the reserve requirements is described in Section 2.2.4.

The above reserve requirements are applied to GenTrader runs in Block B and affect the system production cost through the unit commitment and dispatch process. When performing unit commitment, Block B uses actual hourly load and PV production as well as includes reserve requirements to cover forecast uncertainty and load and PV variability. Compared to the real-world situation, where generation is scheduled based on load and PV forecasts, such treatment will usually incur a lower production cost, and therefore the PV integration cost results may be more conservative.



Note: 1. Operating reserve requirements; 2. Hourly resource schedules; 3. Minutely dispatch results and cost.

**Figure 2.4.** Block Diagram of the Study Procedure

Block C in Figure 2.4 performs minute-by-minute dispatch simulation using ESIOS. Although actual AGC systems operate at 2-second or 4-second intervals, 1-minute time resolution is deemed sufficient to capture the impact of PV production on system frequency regulation, which is the main purpose of AGC systems. The AGC model in ESIOS deploys reserves on AGC units to control the area control error (ACE). The Operator Model within ESIOS monitors system reserves and operates peaking units to control ACE and meet control performance requirements. System control performance can be evaluated to make sure that a desired CPS compliance range is achieved. Unit commitment, energy curtailment, reserve requirements, peaking units dispatch strategy or other assumptions may be adjusted to improve control performance, although no energy curtailment was performed in this study. Detailed descriptions of the AGC and intra-hour dispatch models in ESIOS can be found in [6].

In summary, data provided by Duke Energy and from simulations by the analysis team were used in an operational model to dispatch the Duke Energy system with various levels of installed PV capacity. Comparing results across the simulations provides an estimate of additional reserves and production costs for successively higher PV penetration rates.

### 2.2.3.3 Energy Production Cost Runs

The purpose of production cost modeling is to estimate operational costs of meeting demand with a specified generation fleet. It has been applied in the development of the most economic unit commitment and dispatch solutions in day-to-day operations, as well as finding the most optimal resource build-out in capacity planning. PV generation impacts on energy production cost can be quantified through such modeling approach by adding PV production to an existing resource expansion plan. Operating reserves to cover additional forecast uncertainty and within-hour variability caused by PV are modeled in the unit commitment step as constraints.

Because energy production cost modeling only captures costs on the conventional generation units (fuel, startup and O&M), total system production cost will decrease as PV penetration rate becomes higher and PV generation serves a larger portion of load. For this reason, the integration costs discussed in Section 2.2.3.1 will be hidden by the reduction of energy served by the conventional fleet. It is well-recognized that estimation of PV integration costs has to be made by the comparison of production cost between the PV case and another case where the same amount of energy from conventional generation is provided [20]. A reference case was, therefore, developed for comparison with each PV case. PV integration costs on energy production was derived by comparing the reference and integration/PV cases:

1. Integration case: This is the case with PV generation. PV power output is modeled as negative load. Conventional generators are dispatched to meet net load, which is system load minus PV production.
2. Reference case: A reference generator (same as the term “proxy” used in some literatures) is introduced to replace PV output in the integration case. Conventional generators are dispatched to meet a reduced system load, which is system load minus reference generator production.

The daily energy for reference generation is equal to daily PV energy; consequently, the energy served by the conventional generating fleet is the same in the integration case and the reference case. Therefore, PV integration cost can be determined by comparing the energy production cost between the two cases.

The reference generation profile requires a few other considerations besides equaling PV energy. The methodology is described in Section 2.2.5.

In the simulations, GenTrader runs determine unit commitment and schedules for baseload and AGC generation resources, while ESIOs redispatches AGC, pumped storage and peaking units. The production cost of each run is calculated by combining GenTrader and ESIOs cost components as shown in Table 2.2.

**Table 2.2.** Cost Components and Sources

Cost Components <sup>(a)</sup>	Startup	Fuel	Variable O&M	Fixed O&M
Base load units	GenTrader	GenTrader	GenTrader	GenTrader
AGC units	GenTrader	ESIOS	ESIOS	ESIOS
Peaking units	ESIOS	ESIOS	ESIOS	ESIOS
Pumped Storage	ESIOS	N/A	ESIOS	N/A

<sup>(a)</sup> The definition of startup, fuel and O&M costs are slightly different in GenTrader and ESIOs. In ESIOs the startup cost also includes startup fuel and startup O&M, while in GenTrader these items are included in the fuel and O&M costs. Therefore, final energy production cost was calculated as GenTrader production cost plus the differential of AGC, peaking and pumped storage unit costs after and before re-dispatch by ESIOs, to avoid any double counting, instead of directly adding each component together.

The process to perform energy production cost simulations in each case follows: Block A > Block B > Block C, as shown in Figure 2.4 and described in Section 2.2.3.2,

## 2.2.4 Reserve Requirements

### 2.2.4.1 Types of Reserves

In the Duke system, the following reserves are used in operations:

- Day-ahead planning reserve (DA PR): Additional generation required in DA planning that are intended to mitigate forecast errors (uncertainty), within-hour variability and loss of generation. However, it is assumed that the current contingency reserve requirement (as dictated by the VACAR Reserve Sharing Group) does not increase regardless of the amount of PV integration. With respect to this study, DA PR refers only to the components associated with forecast uncertainty and variability with system generation and load.
- Regulation reserve (RR): RR the reserve needed to cover minute-by-minute variations of load and PV. RR requires fast response and therefore must be provided by units on AGC. RR is also a component of DA PR.

Dynamic operating reserves that vary with hour of the day were applied in the unit commitment process in the study. In general, response time of up to one hour is acceptable for PR. Therefore, PR can be fulfilled by AGC, other online or offline units, or storage and demand response resources<sup>1</sup> that can

<sup>1</sup> Because of the requirement of advanced notice and limitation on the number deployments of demand response resources in the Duke Energy system, demand response was not used for DA planning reserves. It is not used for regulation reserves either due to the limitation of response time and uncertain availability. However, as better

respond within 1 hour. Table 2.3 summarizes the types of reserves and the resources that can provide them.

**Table 2.3.** Types of Reserves and Qualified Resources

Reserves	Qualified Resources
DA PR Up	Online base and AGC generation, online and offline units, pumped storage and demand response resources that can respond within one hour
DA PR Down <sup>(a)</sup>	Online base and AGC generation, online peaking units, pumped storage and demand response
RR Up	Online AGC generation and pumped storage
RR Down	Online AGC generation and pumped storage
<sup>(a)</sup> The current operation practice at Duke Energy does not involve a DA PR down requirement, other than having a plan as to what units will be taken off and in what order if there is minimum load or over generation issues. The reason is that without the presence of significant variable generation, the issue of generation “tripping on” (generation showing up that was not expected) does not exist. Over generation does not happen very often. With high penetration of solar, generation can actually “trip on,” which requires system operators to manage differently.	

#### 2.2.4.2 Day-ahead Planning Reserve Calculation

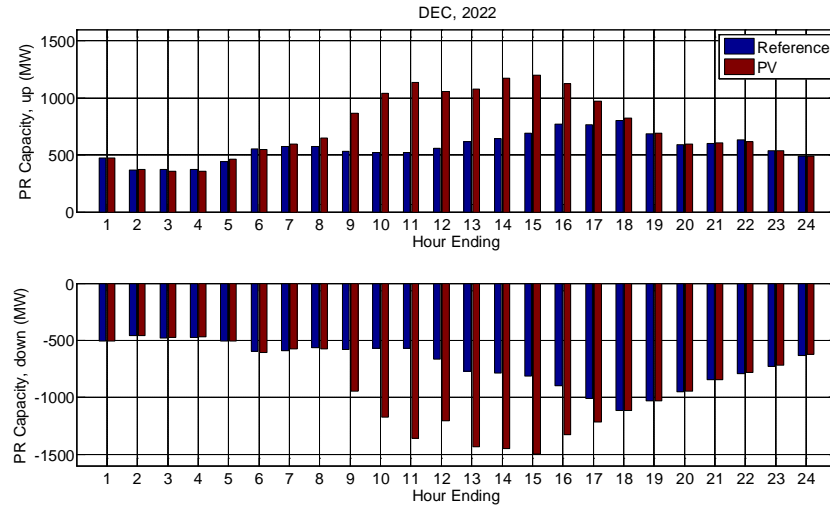
DA planning reserve for the reference case is calculated as the difference between the actual load and DA load forecast. For the PV case, it is the difference between the actual *net load* and the DA forecast of *net load*, where *net load* = load – PV. When forecast data is not available, which is true for future study years, statistical models can be constructed based on historical forecast performance to simulate forecast errors. Such approach is used in this study (details are described in Section 2.2.4.4).

DA planning reserves in the PV case can be greater (for upward reserve) or less (for downward reserve) than the reference case because of the additional forecast uncertainty and variability with PV production. The reserve values were calculated for each operating hour, using the following procedure:

1. Calculate the DA planning reserve requirements time series (load or net load minus its DA forecast) for the entire month, with 1-minute resolution
2. For each operating hour, group all the reserve requirements data within this hour during the entire month
3. Rank all the data within this hour and truncate 5 percent of the points. This will give us 95 percent of confidence level to meet control performance requirements within this hour
4. Find the maximum and minimum values of the truncated time series as the DA planning reserve requirements for this operating hour
5. Ten series of Monte Carlo simulations are used to provide a more robust evaluation. The final PR values are the average of the 10 runs.

Figure 2.5 shows an example of DEC system DA planning reserve requirements (without contingency reserve) in year 2022, comparing the PV and reference cases.

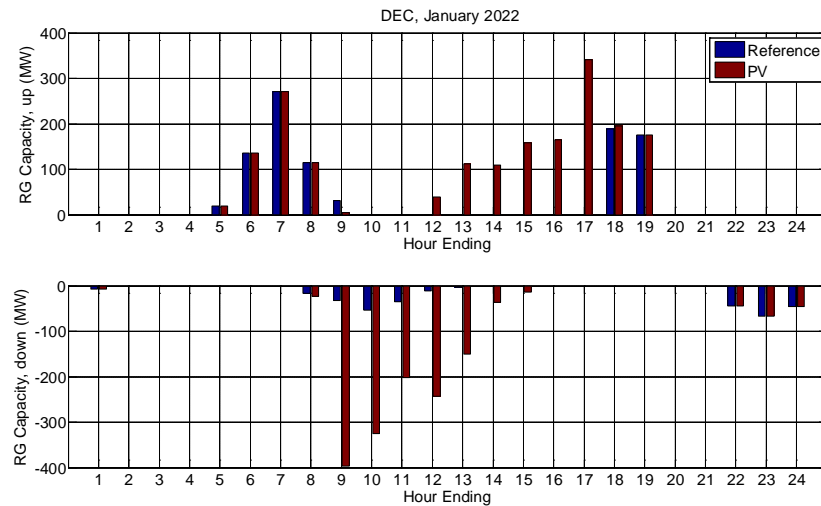
demand response models and operation techniques are developed to manage the limitations, demand response is expected to provide these reserves in the future.



**Figure 2.5.** Example of DA Planning Reserve Requirements

### 2.2.4.3 Regulation Reserve Calculation

Regulation reserve is calculated as the difference between actual net load and real-time schedule of net load. There are multiple approaches to create real-time forecasts. A persistence model is used in this study (details can be found in Section 2.2.4.4). A similar procedure to DA planning reserve calculation is applied to find the regulation requirements for each operating hour in a month. The  $L_{10}^1$  limit of CPS2 is deducted from RR requirement because ACE values within the  $L_{10}$  limit are allowed. ACE is simulated as the imbalance between generation and load. Figure 2.6 shows an example of DEC system RR requirements in year 2022, comparing the PV case and reference case.



**Figure 2.6.** Example of Regulation Reserve Requirements

<sup>1</sup>  $L_{10}$  is the bound for ACE 10-minute averages in CPS2 calculations, above which a violation is counted for a 10-minute period.

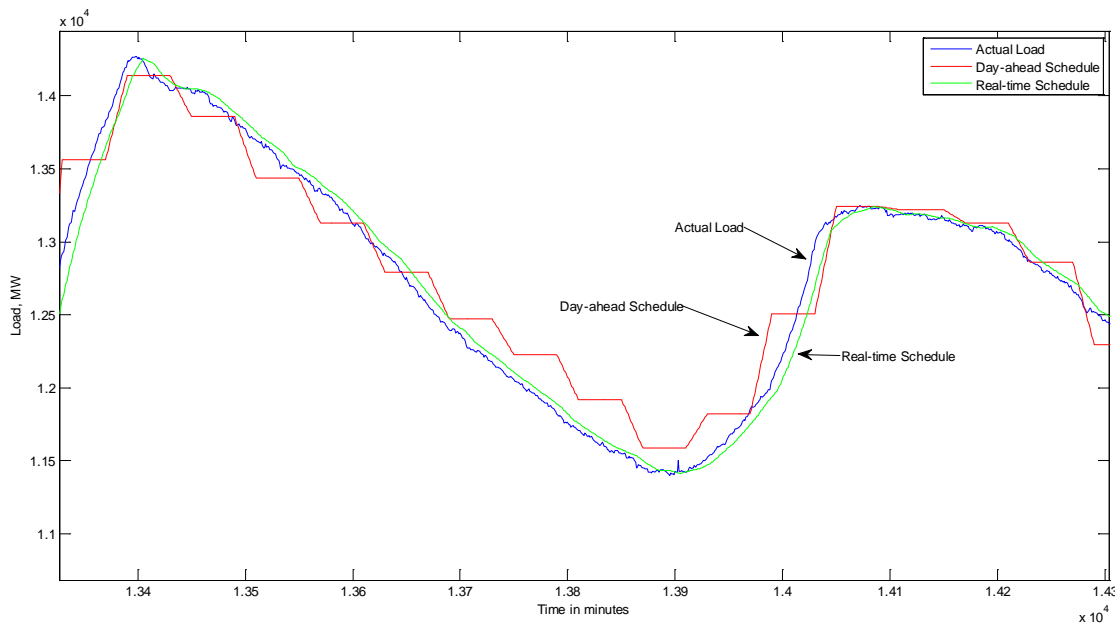
## 2.2.4.4 Day-ahead Forecast and Real-time Forecast

### A. Load Forecast Error Model

Day-ahead forecast and real-time forecast are used in the calculation of DA planning and RR requirements, respectively. DA forecasts are modeled using the approaches described in detail in Appendix A. Construction of the forecast error model was based on historical forecast data. Such model allows analysis to be performed for years when historical forecast data are lacking, whether it is in the past or in the future.

The real-time load forecast was constructed based on minute-by-minute load data, using the naïve persistence model with 10-minute interval. The naïve persistence model assumes that the load is the same as what it was a certain number of minutes ago (10 minutes forecast lag time is used in this study). Then a 10-minute ramp length between two real-time forecasts was added.

Figure 2.7 illustrates the day-ahead and real-time load forecasts.

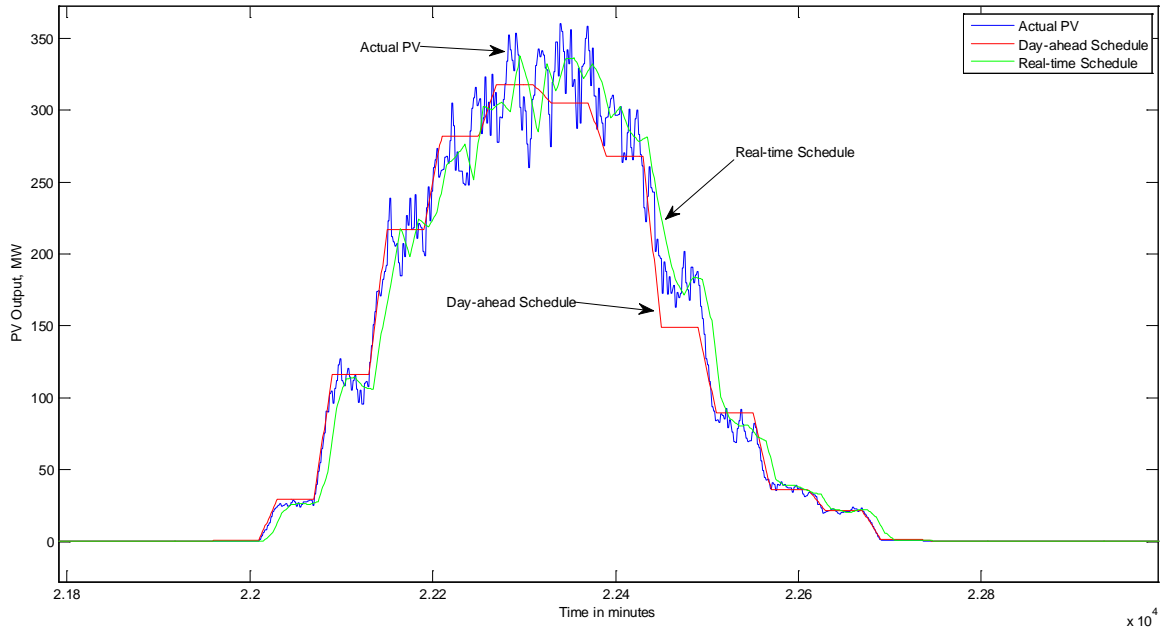


**Figure 2.7.** Illustration of DA and Real-Time Load Schedule

### B. PV Forecast Error Model

PV forecast error model was constructed for the aggregated PV output at the BA level. The methods used for generating DA and real-time PV forecast errors are similar to the ones used for system load. The PV forecast is affected by daily weather conditions measured using clearness index (CI). Forecast error is limited to the maximum output of each operating hour. Additional treatment that associates PV forecast errors with the CI is applied to reflect the above properties. Detailed steps are described in Appendix A.

The same persistence model for the real-time load forecast is used to calculate the real-time PV forecast. Day-ahead and real-time PV forecasts are illustrated in Figure 2.8.



**Figure 2.8.** Illustration of DA and Real-Time PV Schedule

Table 2.4 lists the main parameters needed for the models to quantify reserve requirements.

**Table 2.4.** Parameter List used for Calculation Reserve

Parameters	Values
Study Year	2014
Study with Forecast Error?	Yes
Study with Solar?	Yes
L10_DEC	106.78 MW
L10_DEP	83.79 MW
Real-time Forecast Interval	10 minutes
Real-time Forecast Ramp	10 minutes
Real-time Forecast Lag Time	10 minutes

### 2.2.5 Reference Generation Profile

To compare a PV case to the reference case, it was necessary to duplicate the energy produced in each PV case on a daily basis. This ensures conventional generators in both cases are dispatched to meet load on an equivalent basis. The following goals were considered when developing the profile of reference generation:

1. Daily energy produced by reference generation is equal to the daily energy of PV generation
2. Reference generation does not increase the amount of ancillary service requirements
3. Reference generation does not force more cycling of conventional generators.

Various types of reference generation profiles have been proposed in existing studies, usually only partially meeting the above goals [20]. In this study, an improved approach for the reference generation profile is developed as follows:

Define:

$t = 1, 2, \dots, 24$ , representing the 24 hours of a day.

$PV(t)$  is the PV production in hour  $t$ .

$Load(t)$  is the load in hour  $t$ .

$Pref(t)$  is the output of reference generator in hour  $t$ , which can be obtained from (1)

$$Pref(t) = \{Load(t) - \min[Load(t)]\} * k \quad (1)$$

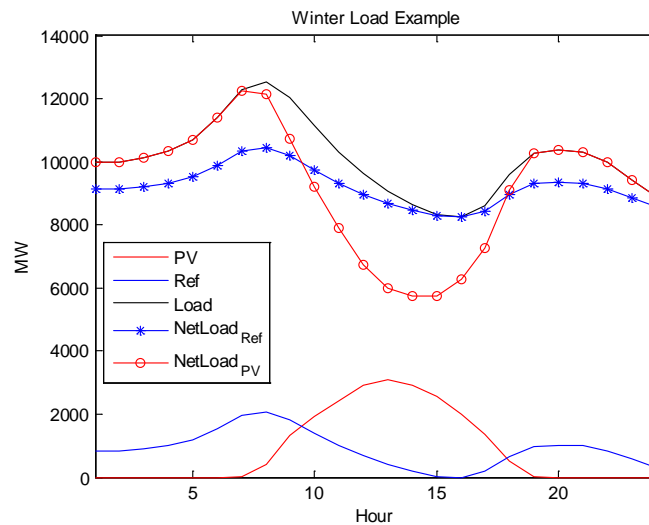
where  $k$  can be determined by inserting (1) into (2)

$$\sum_{t=1}^{24} Pref(t) = \sum_{t=1}^{24} PV(t) \quad (2)$$

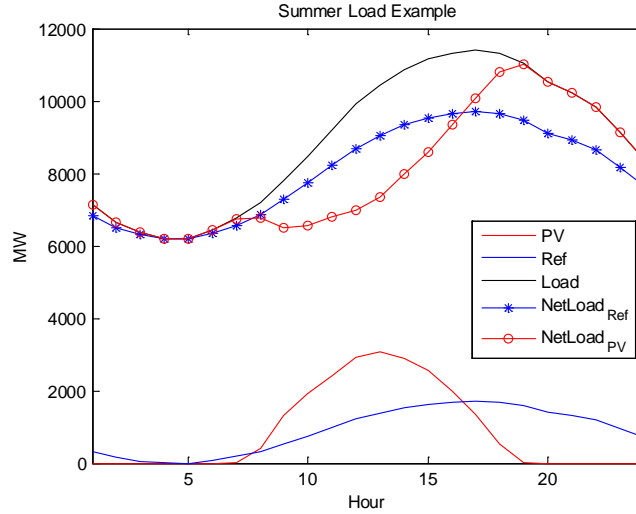
Equation (2) means that the reference generation produces the same amount of daily energy as PV. Combining (1) and (2), we get

$$Pref(t) = \{Load(t) - \min[Load(t)]\} * \frac{\sum_{t=1}^{24} PV(t)}{\sum_{t=1}^{24} Load(t) - \min[Load(t)]} \quad (3)$$

Reference generation profile can be provided by a dispatchable generator, and is an alternative to produce the same amount of energy as PV, but optimized to reduce its impact on system operating reserve requirements and the operation of other generators. The energy value of the reference generator would be similar to PV, therefore, the production cost difference between the PV/integration case and the reference case can be attributed to ancillary services and other impacts (the cost components listed in Section 2.2.3.1) of integrating PV. Figure 2.9 and Figure 2.10 illustrate the results produced using the above approach.



**Figure 2.9.** Reference Generation Profile-Winter



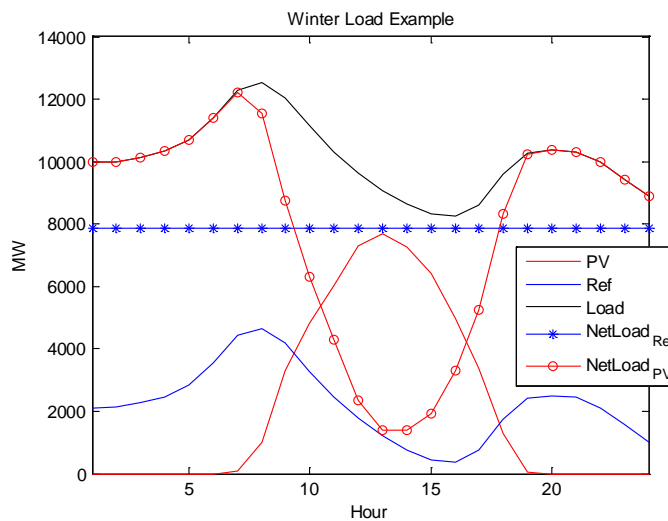
**Figure 2.10.** Reference Generation Profile-Summer

For readers without color, in Figure 2.9, the highest curve on the top is load. The curve immediately below the load curve with asterisk is load minus reference generation, or net load of the reference case. For comparison, the curve with circles is load minus PV generation. The PV production profile is one of the two bottom curves; the one that peaks in the middle of the day. The other curve on the bottom is the reference generation profile. Figure 2.10 follows the same arrangement.

Although not an issue in the cases investigated in this study, it is possible that  $k$  can become greater than 1 when PV penetration is very high. In this situation, we can calculate  $Pref(t)$  using (4), which lets the reference generator take care the entire variable portion of the load:

$$Pref(t) = \{Load(t) - \min[Load(t)]\} + \frac{\sum_{t=1}^{24} PV(t) - \sum_{t=1}^{24} Load(t) - \min[Load(t)]}{24} \quad (4)$$

Figure 2.11 illustrates a case when  $k > 1$ , with the same arrangement of curves as for Figure 2.9.



**Figure 2.11.** Reference Generation Profile-Winter ( $k > 1$ )

## 2.3 Data Inputs and Assumptions

### 2.3.1 Study Scenarios

Table 2.5 lists the study scenarios and cases in the generation impact study.

**Table 2.5. PV Penetration Cases**

(MWac)	2014	2016	2018	2020	2022
Compliance					
DEC	361	631	785	1,012	1,197
DEP	312	312	334	395	483
Mid					
DEC	431	816	1,393	2,006	2,598
DEP	331	506	867	1,248	1,642
Smooth High	2.5%	5%	10%	15%	20%
DEC	500	1,000	2,000	3,000	4,000
DEP	350	700	1,400	2,100	2,000

Three different PV penetration rates were simulated, ranging from the minimum amount to meet state RPS requirement (compliance scenario) to rates based on current expectations from the interconnection request queue (mid penetration scenario) to aggressive projections (high-penetration scenario).

Each PV scenario is based on the geographic and size distribution of existing PV installations along with those in the interconnection queue.

The assumptions of the thermal fleet, load, fuel price, and market transactions come from the Duke Energy IRPs and consequently change from year to year. PV impacts at different penetration levels were assessed and compared between compliance, mid and high-penetration cases for the same study year.

### 2.3.2 Data Inputs, Models and Assumptions

#### 2.3.2.1 Load Data

The system load shape in each study case is based on the 2012 historical system load with adjustments to include Duke native and co-owned full requirements loads. System load forecast for future years (from 2014 to 2022) is computed by scaling the 2012 load shape to match the annual energy and peak forecast of those years as published in the IRP filing, while adjusting for the effect of leap year as well as different day of week at the beginning of each year.

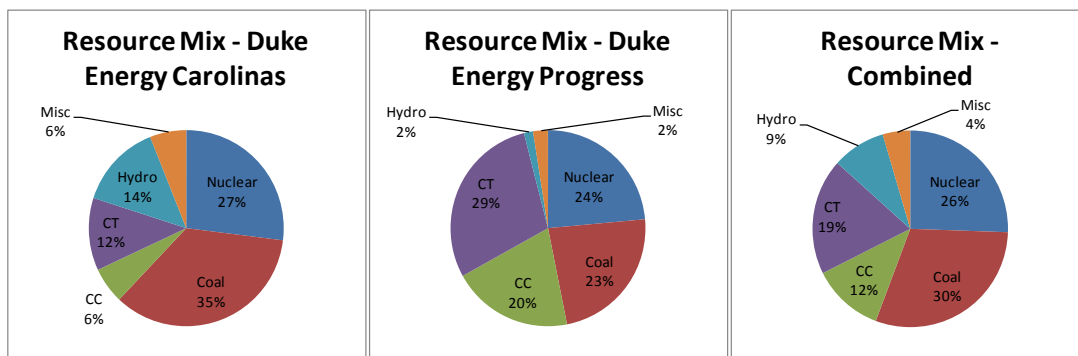
### 2.3.2.2 PV Production Data

To produce PV generation data for the study cases, the output of a representative 1 kW system is simulated for each zip code in the Duke Carolinas area. Weather from 2012 was used to correlate with load shape. Production profiles of the 1 kW systems are then scaled up to projected PV installation capacity in each study year. The projected PV sites in the study cases range from a few kW to a couple hundred MW of installed capacity. A summary of PV data used is as follows:

- Hourly 2012 PV production time series for each 1 kW-AC system.
- Hourly future production time series for DEC fleet and DEP fleet based on 1 kW-AC 2012 production sets and capacity forecasts for future years and scenarios.
- 1-minute resolution 2012 production time series for each 1 kW-AC system.
- 1-minute resolution future production time series for DEC and DEP fleets, scaled as the hourly data.

### 2.3.2.3 Generation Data

The Duke Energy generation portfolio extends across three balancing areas in North and South Carolina. The approximately 36,000-MW portfolio is jointly dispatched to serve customers of the DEC and DEP areas. The resource mix is described in Figure 2.12.



**Figure 2.12.** Resource Mix of Duke System Fleet

The generation fleet/resource plans used in energy production cost modeling is adopted from IRP plans for the compliance scenario, which depends on IRP load forecast and PV penetration assumptions for the compliance scenario in each study year. Therefore, the fleet can be slightly different from year to year because of generation retirement or new resource build-out as needed, but the conventional generation mix remains the same for different PV penetration scenarios in the same study year, allowing the results from these cases to be comparable.

Fuel and emission price forecasts and long-term contracts are also adopted from the IRP plan. Short-term and spot market transactions are excluded from consideration to reduce additional uncertainties in the study. Nuclear units are modeled as must-run.

#### 2.3.2.4 Pumped Storage

In the DEC system, a cascaded pumped storage (PS) system with 3 reservoirs and 2 groups of pumps/generators is used for peak shaving. When the PS is in generation mode, it can also provide regulation service. In the study, pump and generation schedules of the PS system is determined in GenTrader to optimize the PS system's energy value. For example, the PS system is set to pump mode around mid-night to utilize low cost energy during these light load hours, and set to generation mode during the morning peak to reduce the need of more expensive generation. Reservoir storage levels determined by the GenTrader schedule are maintained in ESIOS at the end of each operating hour to maintain this optimality in energy value. In the meantime, ESIOS can dispatch PS generators to perform regulation. The regulation capability of the PS system is always called on before the thermal generators because it responds more quickly and at lower cost.

#### 2.3.2.5 Demand Response

DR programs were modeled in GenTrader as follows:

1. Use call options to model DR programs that can be dispatched economically;
2. Use a strike price as the threshold to control the number of times economic DR's are called on;
3. Check in the results total number of hours/times DR's are deployed and make sure they are reasonable. Adjust DR strike price if necessary;
4. Use a MW estimate fixed for each month/season for each DR program based on DR forecast in DEC and DEP;
5. Existing entries of DR programs in the planning model sometimes lump several DR programs together. This simplification was maintained.

An array of existing Duke demand response programs are modeled in GenTrader, including Power Manager® (residential cycling AC), PowerShare® (commercial energy management), and voltage control. The MW capability is forecast seasonally by program type. DR is dispatched in GenTrader with a minimum capacity requirement, similar to generators. Each program is assigned a strike price to establish a dispatch priority relative to the other programs and limit the number of calls. The hourly output from GenTrader is passed to ESIOS as a fixed schedule and not considered in the intra-hour dispatch. Due to the high deployment rate of DA planning reserves and the limited number of calls available (representing the limitation on the number of deployments) on DR programs, as well as the advanced notice requirement for most of them, the DR programs are not configured to provide ancillary services in this study. However, as modeling and control techniques for DR resources are improved to better manage the above constraints, it should be possible to use DR for ancillary services in the future.

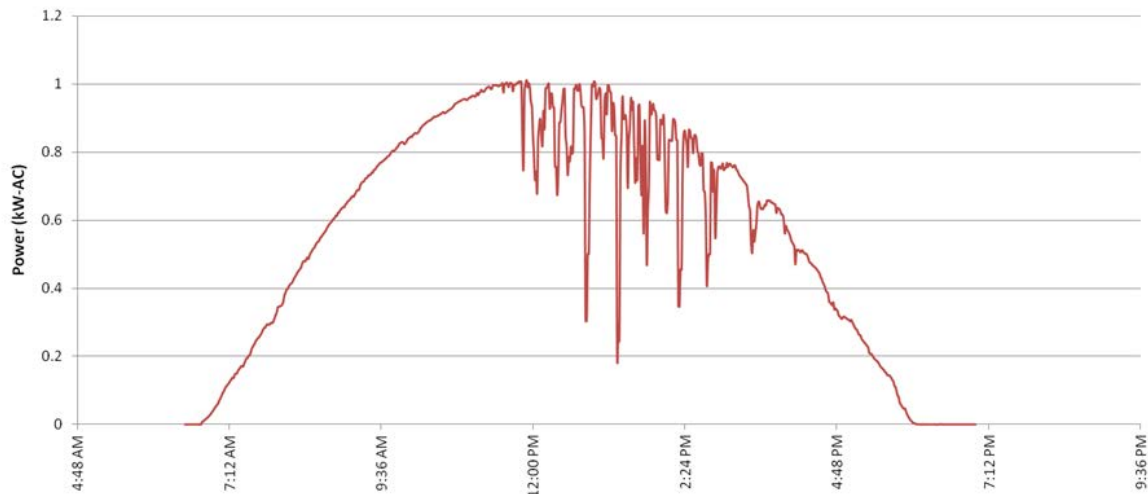
## 2.4 Results

### 2.4.1 PV Production Data

#### 2.4.1.1 Fleet Variability

Generating reserves are based on unanticipated, but probable events, typically weather driven or outage related. To assess the potential magnitude of reserves needed, the largest variation in PV output across the various scenarios was identified. An example occurred in the mid-case simulation on December 29, 2014, for a PV installation on the DEP system. The variation in PV production for this installation for that day is illustrated in Figure 2.13. Figure 2.14 shows the change in power output for this same PV system, contrasted with PV output across the entire Duke Energy system, expressed as a fraction of capacity. The PV fleet output variability for Duke as a whole is less than the variability of a single PV system. This illustrates the importance of including geographic diversity in an analysis of this type as well as integrating intermittent generation across a broad area and multiple balancing authorities.

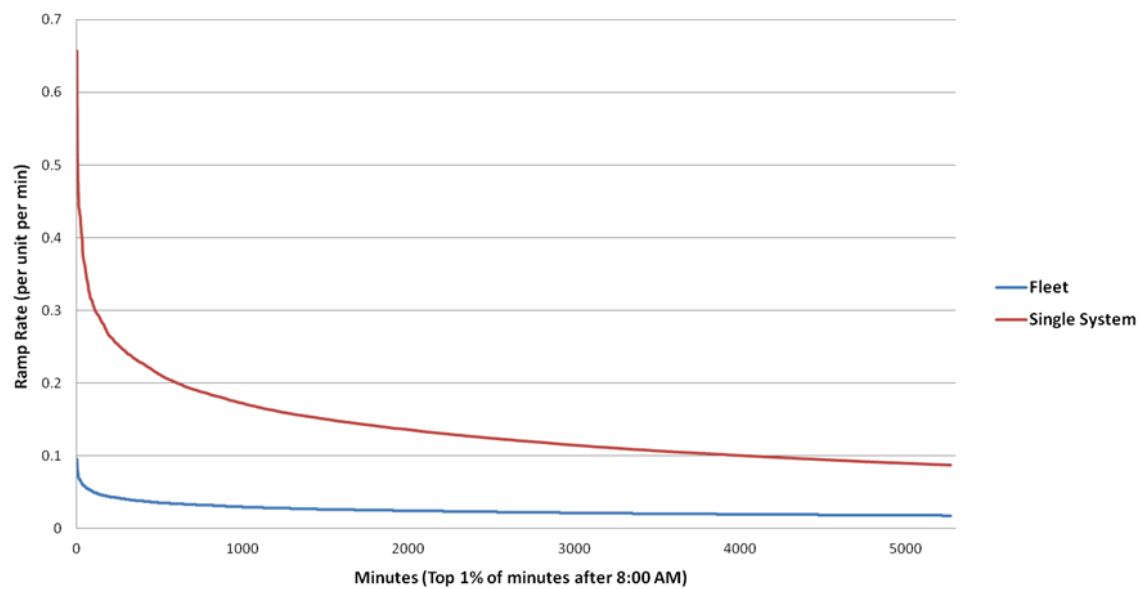
The effect is clearer when ramp rates are sorted from high to low and plotted as a curve. This is shown in Figure 2.15 where the highest 1 percent of highest ramp rates for the example system and the entire PV fleet are sorted. For the example system, the highest ramp rate was about 65 percent of its AC rating, whereas for the fleet, the highest ramp rate was about 10 percent of its aggregate rating.



**Figure 2.13.** DEP-0285 Production on Day of Peak Ramp Rate (December 29, 2012)



**Figure 2.14.** Single System versus DEC Fleet Ramp Rates (December 29, 2012)



**Figure 2.15.** Ramp Rate Duration Curves

#### 2.4.1.2 Statistics of Different Clearness Index Days

##### Approach and Methods

The previous section illustrates the effect cloudiness can have on PV production and required ramp rates for conventional generators to respond to variations in output. In order to model this effect, a “clearness index (CI)” was developed using hourly production data based on actual irradiance [11] and weather conditions to generate a distribution relative to the available “clear sky” energy [13]. Hourly PV production data based on 2012 weather was produced and aligned with clear sky modeled fleet production as described in Section 2.2.2.

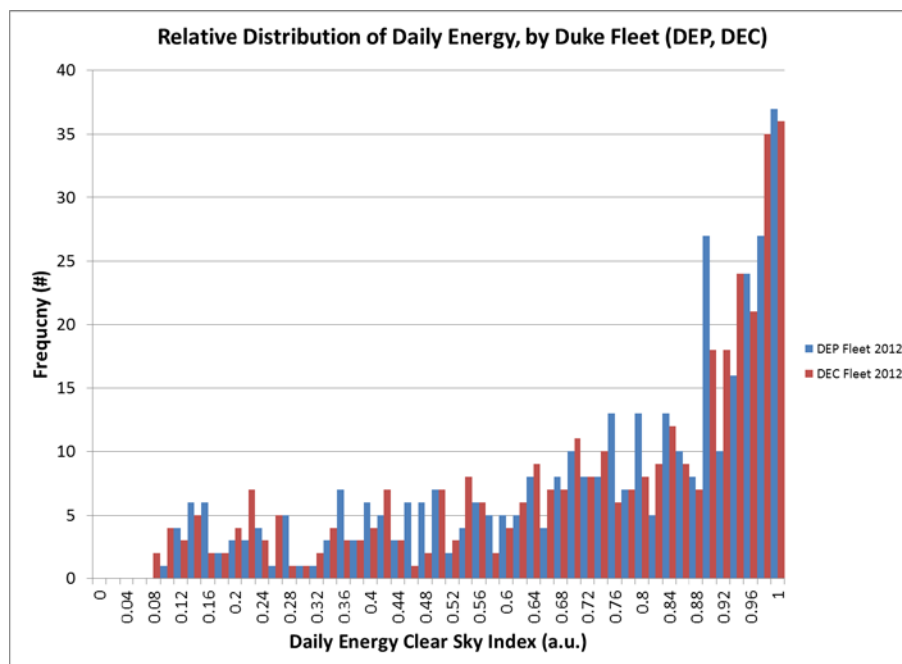
Hourly production data was generated first using the hourly averaged irradiance at each location within the DEC and DEP service territories. Next, individual PV system specifications that were defined by Duke for each region were simulated on a system-by-system basis, using irradiance and weather as inputs. The individual system output was modeled both based on the actual irradiance and weather and also based on the modeled clear sky irradiance. Finally, each individual system output was aggregated to the total fleet level, for both measured irradiance and modeled clear sky.

Further analysis was conducted to assess the CI distribution for 2012. Taking the hourly energy output for the DEC and DEP fleets, daily energy totals were summed. The measured daily total energy for each fleet was then taken as a ratio against the modeled clear sky available energy, called the daily CI. A relative and cumulative distribution of the daily CI was calculated independently for the DEC and DEP fleets.

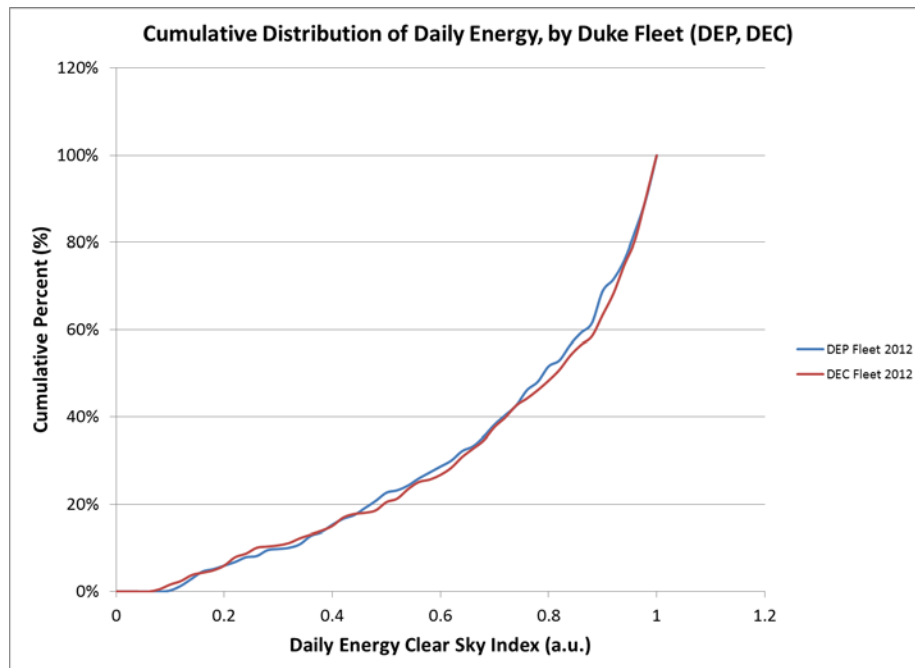
### Results

The daily CI for both DEC and DEP were plotted in Figure 2.16, by relative frequency distribution on scale of 0, being completely dark to 1, being a full sunny day.

From Figure 2.16, we note that greater than 35 percent of days in both regions (141 in DEP, 152 in DEC) fell above a 90 percent daily CI. A separate cluster of days seem to fall between a 60 to 90 percent daily CI, which probably represents days with morning or afternoon cloud formation/dissipation (i.e. partially cloudy, then clear). Days below 60 percent, down to as low as 8 percent daily CI represent persistent or transient cloud coverage throughout the entire day. Zero production is not possible within our measurement technique because of diffuse light energy. Looking at the frequency in cumulative terms produces Figure 2.17.



**Figure 2.16.** Relative Distribution of Daily Energy by Duke Fleet



**Figure 2.17.** Cumulative Distribution of Daily Energy by Duke Fleet

### Discussion

While the distribution of daily CI for both DEC and DEP regions follows a very similar trend, there are notable differences in the results. For the DEP region, a more frequent occurrence in medium (60-90 percent) cloudy days occurs relative to the DEC region. These added, medium cloudy days in the DEP region are offset by the reduction in low (60 percent or less) cloudy days. In simple terms, the DEC region tends to have more sun. This is also observed by comparing the median and mean daily CI value for each region (Table 2.6).

**Table 2.6.** Median and Mean Daily CI Values by Duke Fleet

Region	Median Daily CI	Mean Daily CI
DEP	78.9%	71.6%
DEC	72.3%	81.5%

While showing daily CI for the year 2012, results based on longer-term weather measurements could be useful in generating a larger sample size and an increased confidence interval. This initial estimate will give a probable range of cloudy to clear days, however, weather from 2012 may not be fully representative of future weather trends for this region.

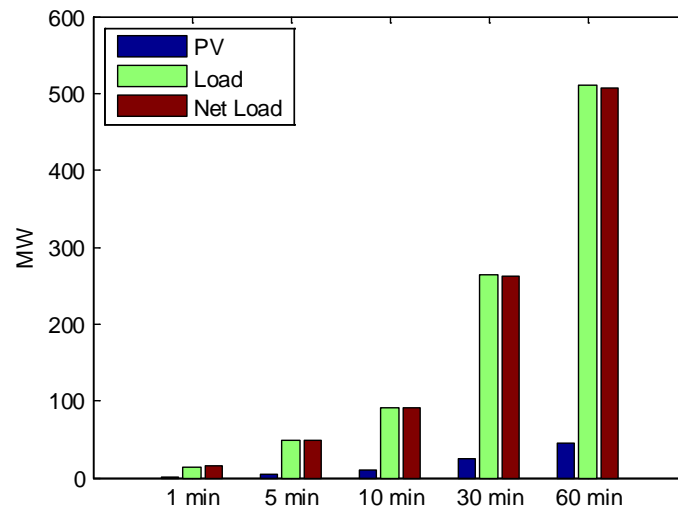
## **2.4.2 Reserve Requirements**

### **2.4.2.1 PV and Net Load Variability**

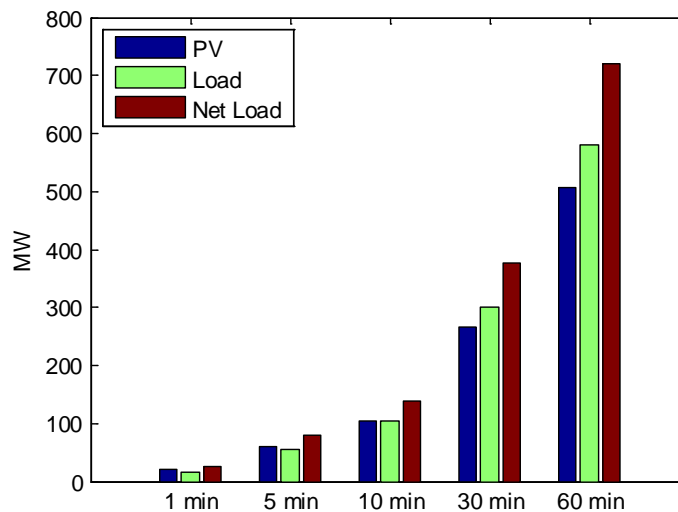
The variability of PV is analyzed by looking at its ramp distribution across multiple different time intervals, from 1 minute to 60 minutes. The 1-minute ramp is the change that PV could make within 1-

minute time period. Such ramps are calculated for each 1-minute interval throughout the year and its distribution can be obtained. A similar procedure is taken to get the distribution of ramps for other time intervals. The standard deviation (std) of these distributions is compared to that of load and net load to understand its significance in the combined variability of the system.

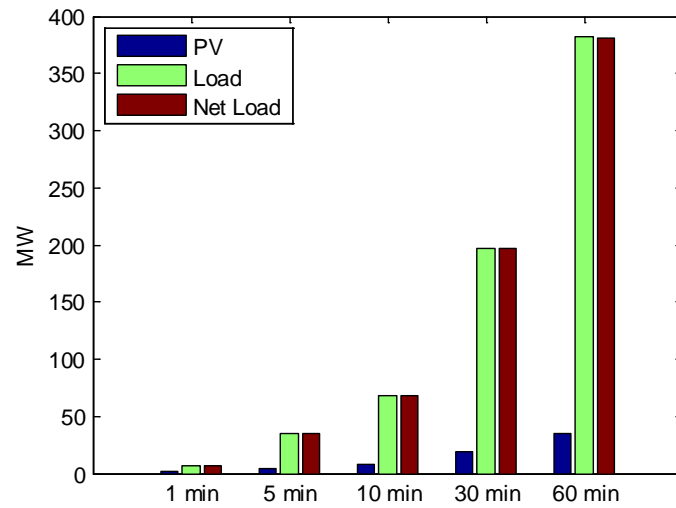
Figure 2.18 to Figure 2.21 show the DEC and DEP 2014 compliance case and 2022 high-PV case results as examples. To provide a context for the comparison of variability between PV and load, DEC and DEP peak load and installed PV capacity in these cases are shown in Table 2.7. Variability results for other cases can be found in Appendix A.



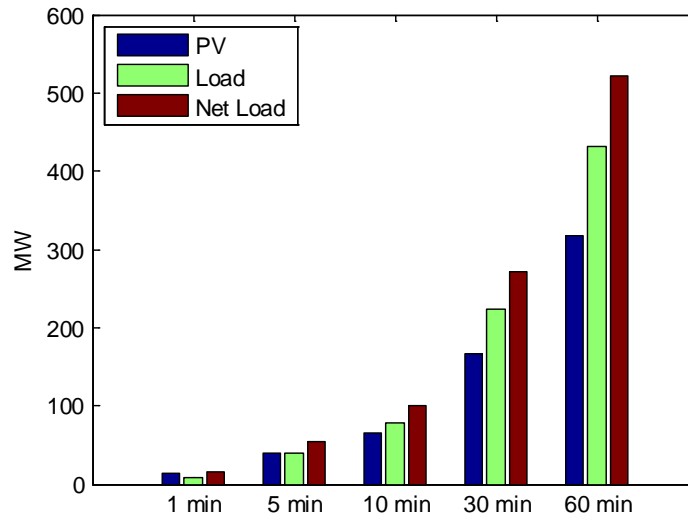
**Figure 2.18.** Standard Deviation of PV and Load Ramps (compliance case 2014 DEC)



**Figure 2.19.** Standard Deviation of PV and Load Ramps (high-PV case 2022 DEC)



**Figure 2.20.** Standard Deviation of PV and load ramps (compliance case 2014 DEP)

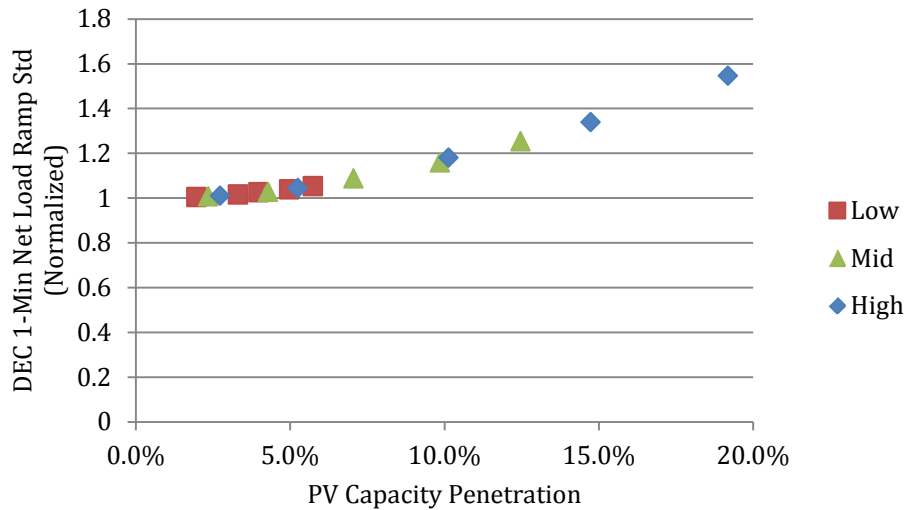


**Figure 2.21.** Standard Deviation of PV and Load Ramps (high-PV case 2022 DEP)

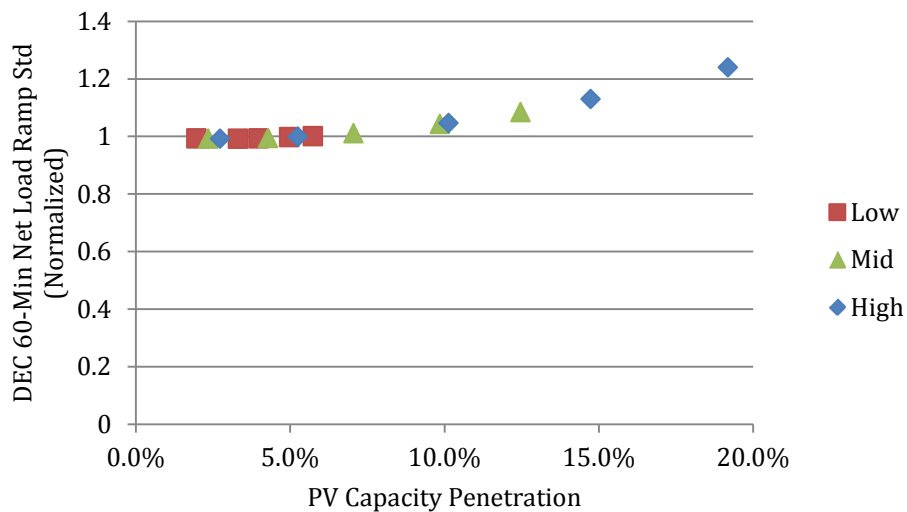
**Table 2.7.** DEC and DEP Peak Load and Installed PV Capacity in Selected Cases

Case Name	Compliance 2014 DEC	High PV 2022 DEC	Compliance 2014 DEP	High PV 2022 DEP
Peak Load (MW)	18,332	20,848	13,016	14,636
Installed PV Capacity (MW)	361	4,000	312	2,800

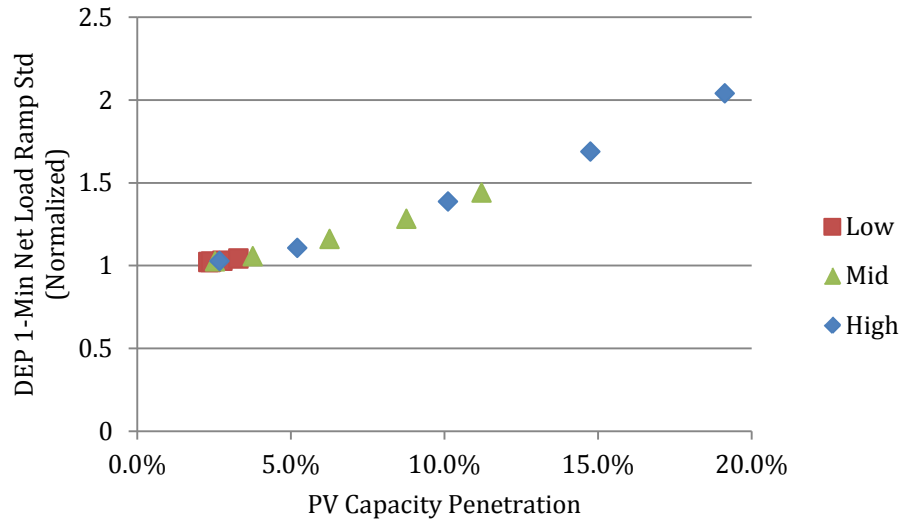
To investigate the relationship between net-load variability and the penetration of PV, the standard deviations of ramp distribution in each PV case are plotted together. The standard deviations of net-load ramps are normalized using the corresponding values of load to eliminate the impact from load growth. This association is shown in Figure 2.22 to Figure 2.25 for ramps during one and 60-minute period and for DEC and DEP systems, respectively. More graphs about PV and net-load variability in different study years and the data values can be found in Appendix A.



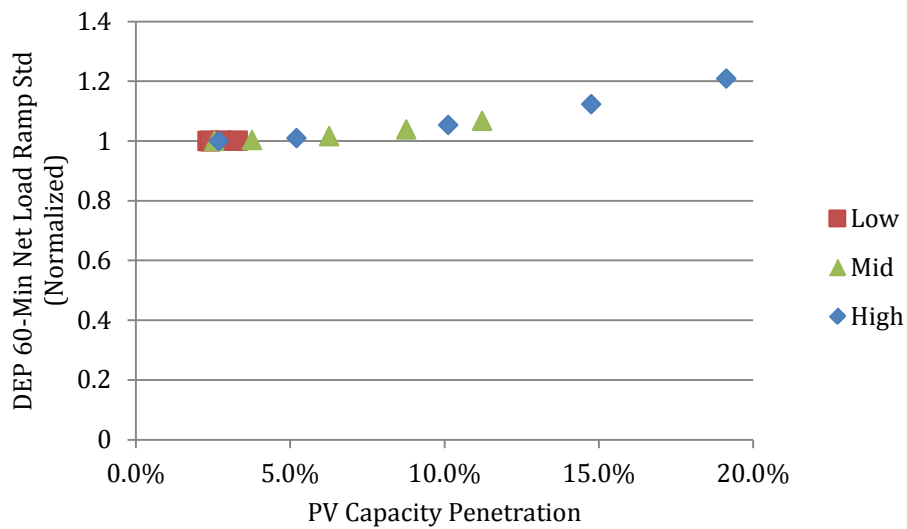
**Figure 2.22.** One-Minute Variability of all DEC Study Cases (shown as the ratio between net load and load without PV)



**Figure 2.23.** Sixty-Minute Variability of all DEC Study Cases (shown as the ratio between net load and load without PV)



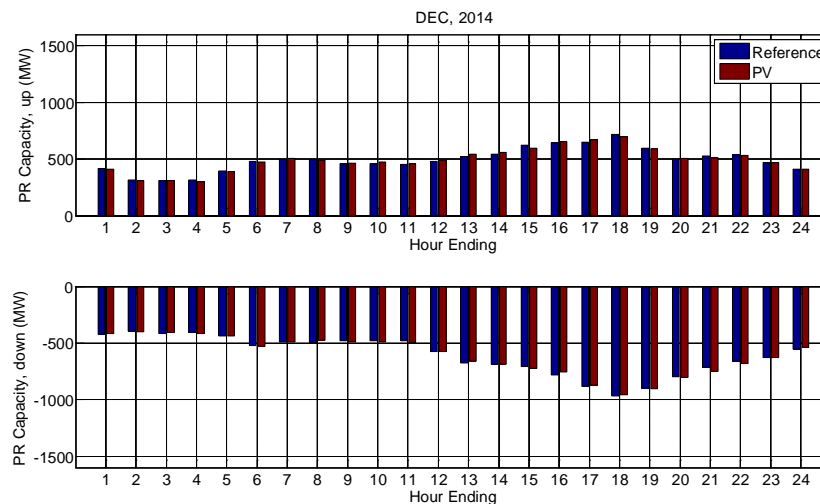
**Figure 2.24.** One-Minute Variability of All DEP Study Cases (shown as the ratio between net load and load without PV)



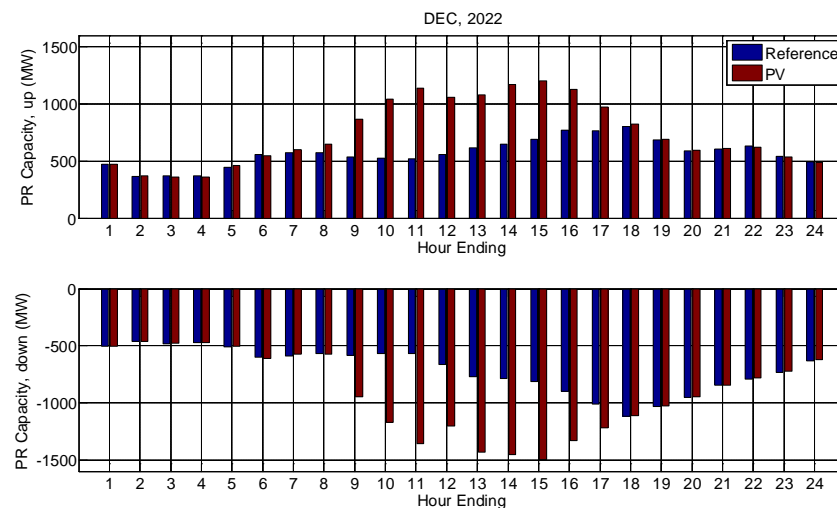
**Figure 2.25.** Sixty-minute Variability of All DEP Study Cases (shown as the ratio between net load and load without PV)

### 2.4.2.2 Day-ahead Planning Reserve

Day-ahead planning reserve is used to cover combined DA forecast errors of load and PV, as well as variability within the hour. It is applied to the unit commitment process in GenTrader to ensure sufficient upward and downward<sup>1</sup> capacity is available to meet unexpected load and PV changes in real-time dispatch. The DA planning reserve requirements for DEC and DEP for two study years, 2014 and 2022, with a low and high-PV penetration level, respectively, are plotted in Figure 2.26 through Figure 2.29.

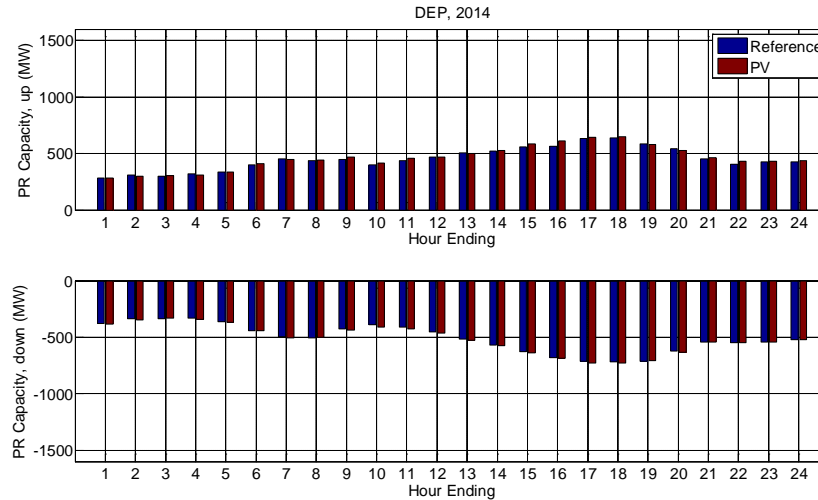


**Figure 2.26.** Planning Reserve Requirements in DEC for the 2014 Low Penetration Case

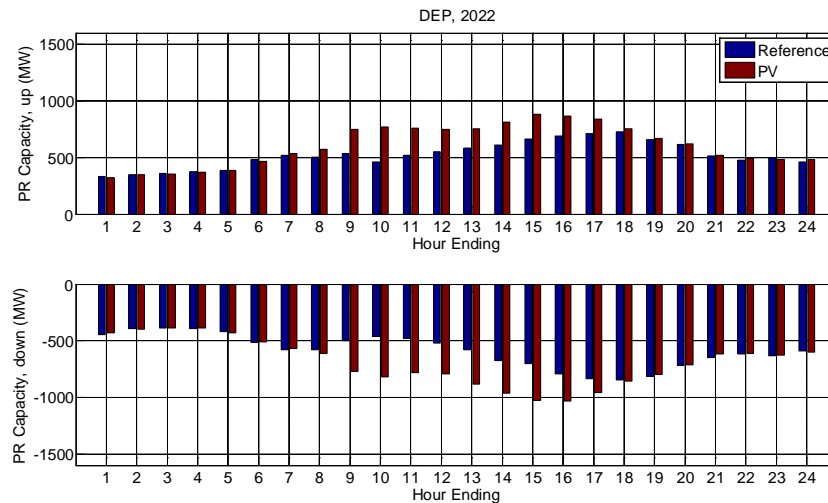


**Figure 2.27.** Planning Reserve Requirements in DEC for the 2022 High-Penetration Case

<sup>1</sup> The current operation practice at Duke Energy does not involve a DA PR down requirement, other than having a plan as to what units will be taken off and in what order if there is minimum load or over generation issues. The reason is that without the presence of significant variable generation, the issue of generation “tripping on” (generation showing up that was not expected) does not exist. Over generation does not happen very often. With high penetration of solar, generation can actually “trip on” which requires system operators to manage differently.



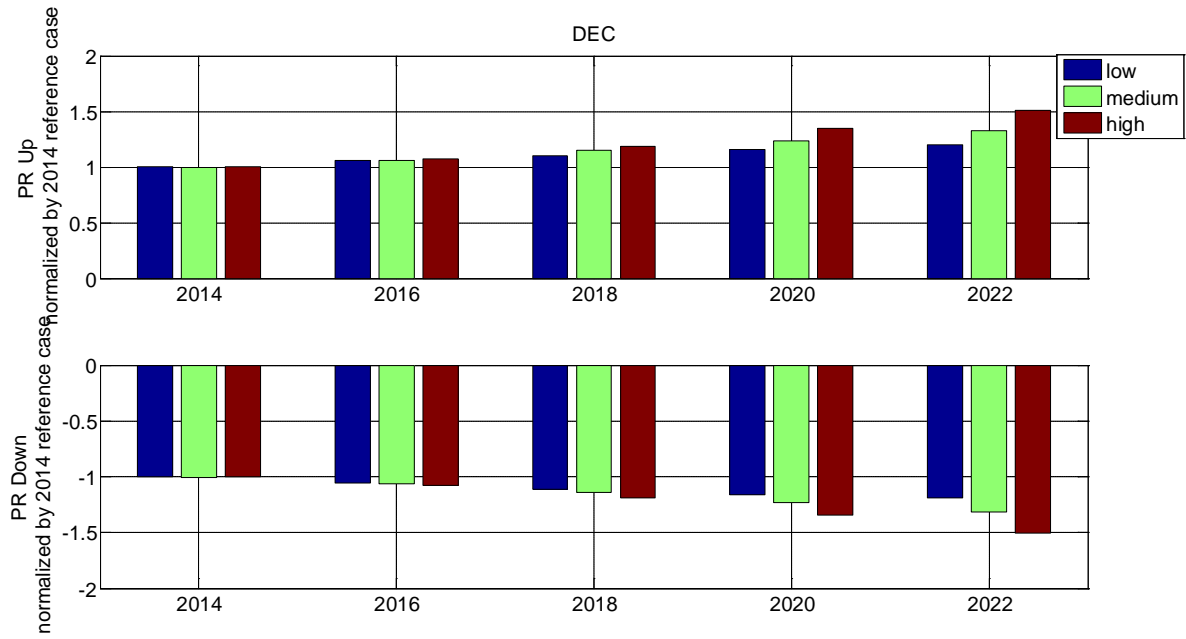
**Figure 2.28.** Planning Reserve Requirements in DEP for the 2014 Low-Penetration Case



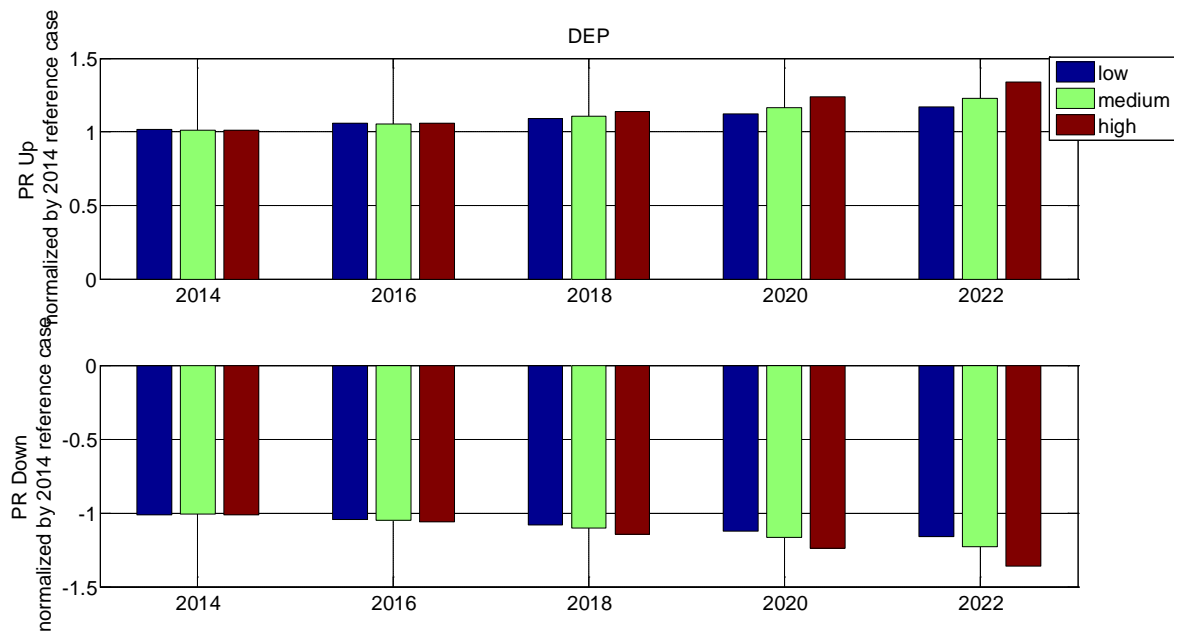
**Figure 2.29.** Planning Reserve Requirements in DEP for the 2022 High-Penetration Case

The trends of DA planning reserve in DEC and DEP for the 5 study years are depicted in Figure 2.30 and Figure 2.31. DA planning reserves are compared between different cases using the sum of reserve requirements of all hours, and normalized by the values in the 2014 reference case. Results for other cases can be found in Appendix A.

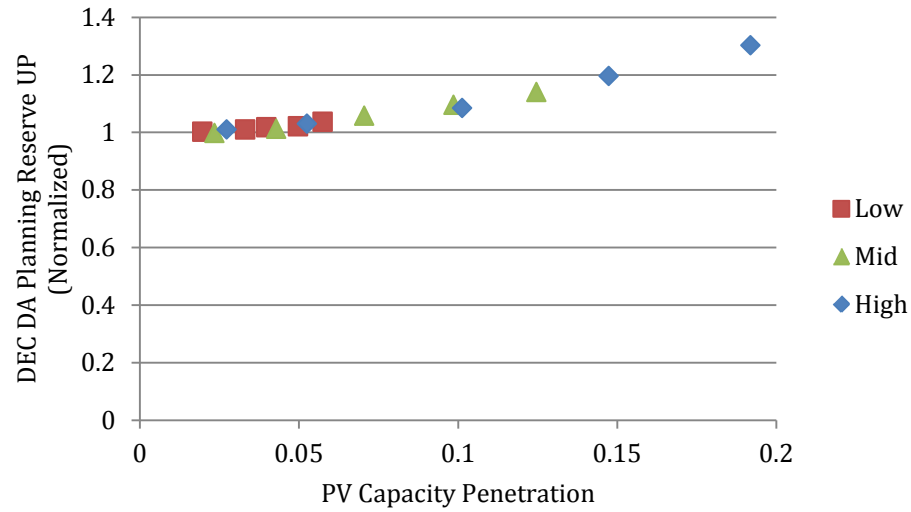
The relation between DA planning reserve requirements and PV penetration rate are shown in Figure 2.32 to Figure 2.35 for DEC and DEP, respectively. The reserve values are normalized using the values in the corresponding reference cases, i.e., reserve requirements without PV. This way the impact of load growth in different study years can be eliminated from the trend plots. The plots show that the DA planning reserve requirements in the DEC and DEP systems increase at a similar or higher rate than the growth of PV penetration level. The increases in upward and downward reserve requirements are roughly symmetrical.



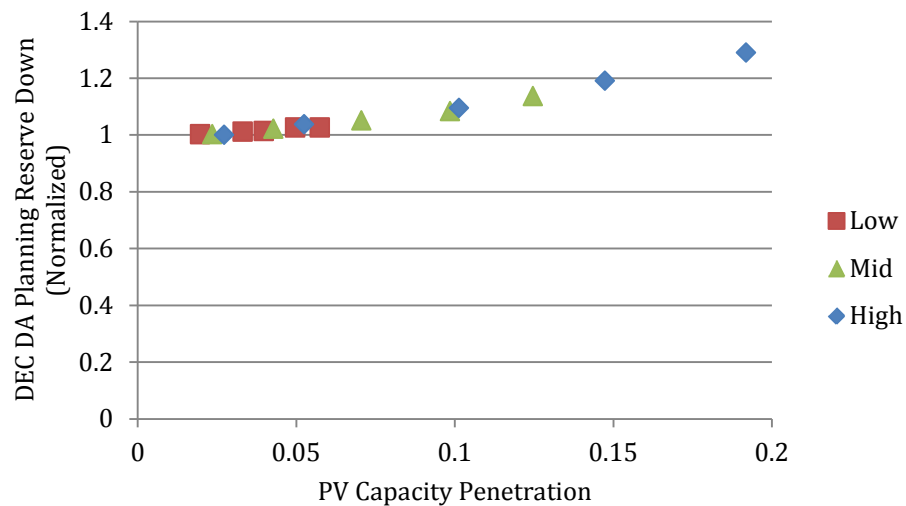
**Figure 2.30.** Trend of the DA Planning Reserve Requirements in DEC



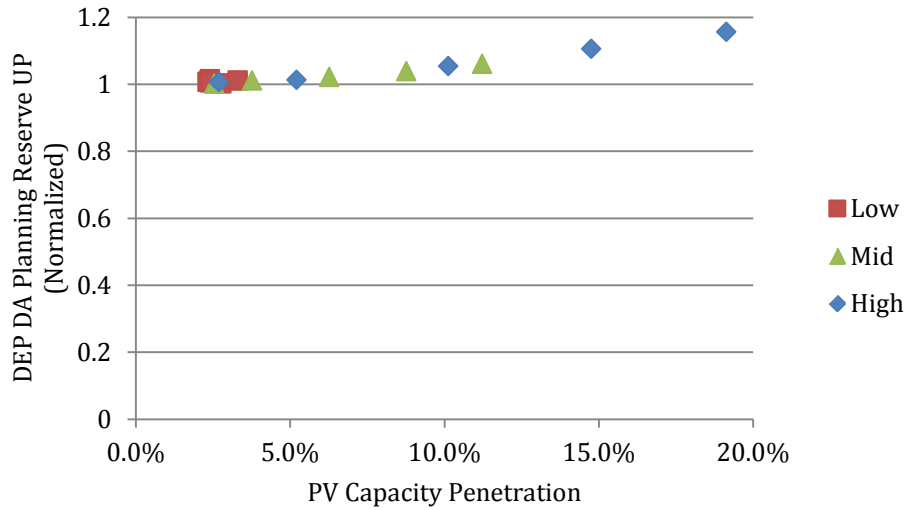
**Figure 2.31.** Trend of the DA Planning Reserve Requirements in DEP



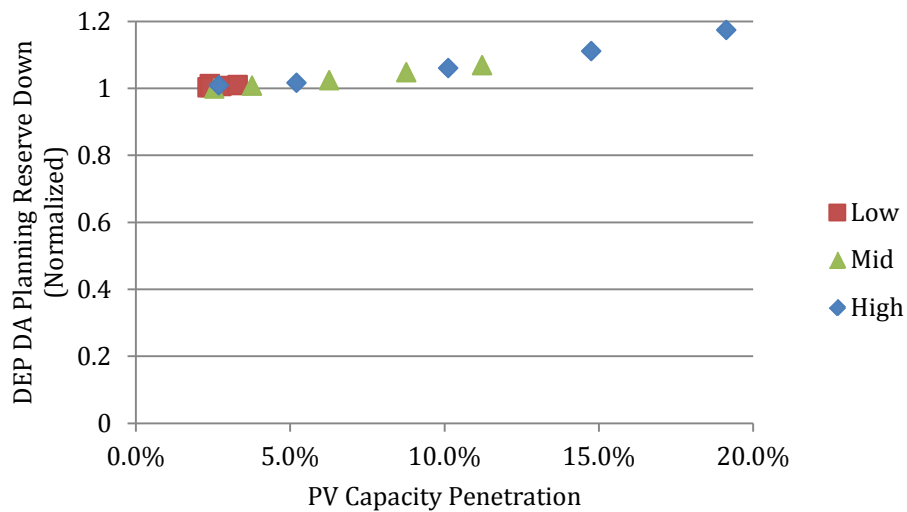
**Figure 2.32.** Planning Reserve Up of All DEC PV Cases (shown as the ratio between the requirements of PV case and corresponding reference case)



**Figure 2.33.** Planning Reserve Down of All DEC PV cases (shown as the ratio between the requirements of PV case and corresponding reference case)



**Figure 2.34.** Planning Reserve Up of All DEP PV cases (shown as the ratio between the requirements of PV case and corresponding reference case)



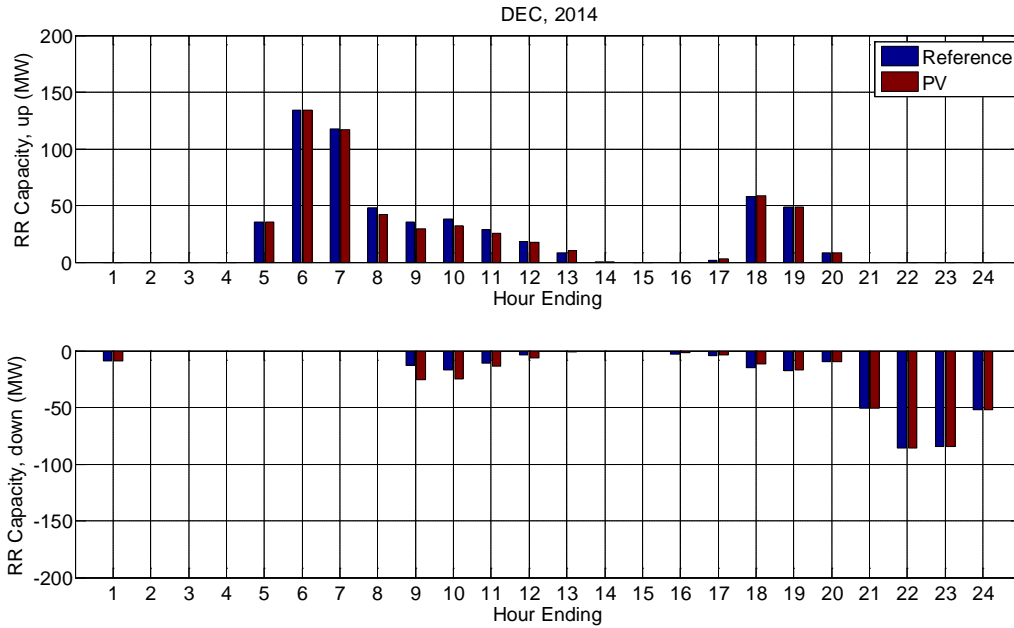
**Figure 2.35.** Planning Reserve Down of All DEP PV Cases (shown as the ratio between the requirements of PV case and corresponding reference case)

The data values of reserve requirements for all study cases can be found in Appendix A.

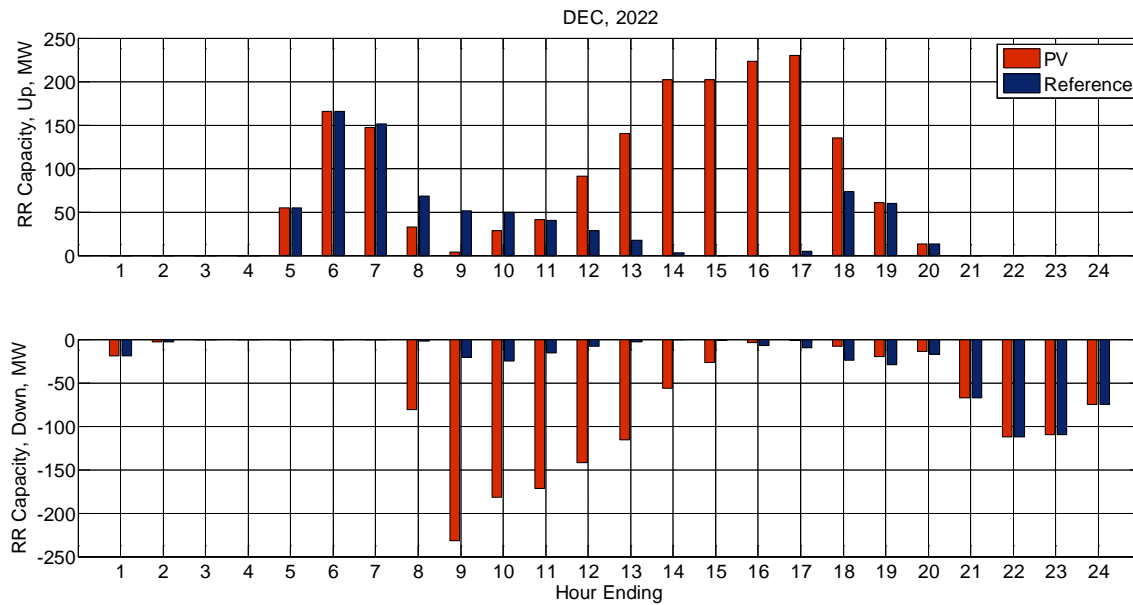
#### 2.4.2.3 Regulation Reserve

Regulation reserve is used to cover the minute-by-minute variation of load and PV. The RR requirement is applied to AGC generators in the unit commitment process in GenTrader, to ensure sufficient upward and downward capacity is available on AGC units to respond to fast changes in the

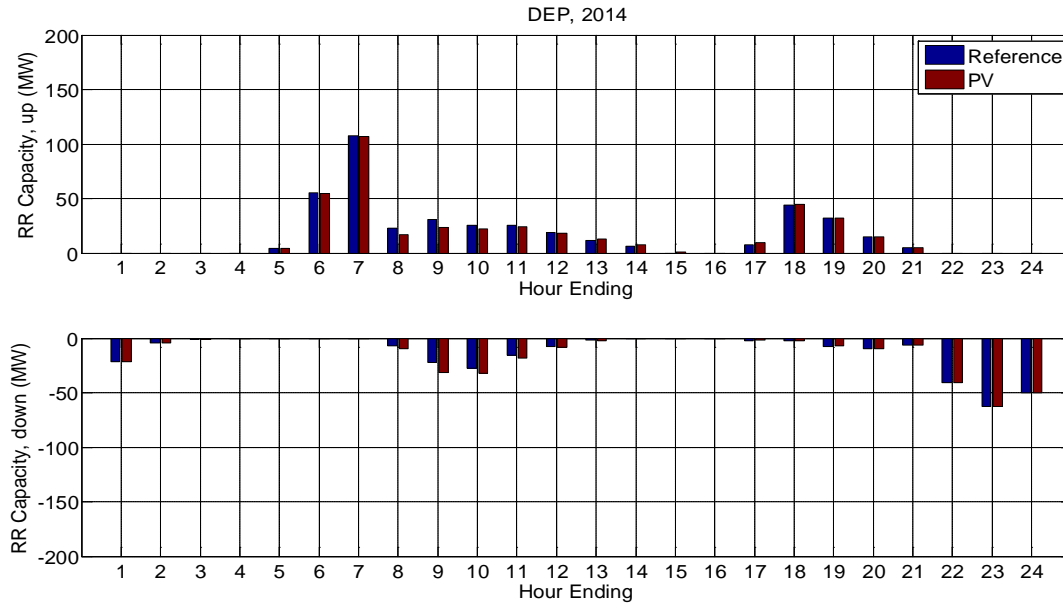
system. The RR requirements for DEC and DEP for two study years, 2014 and 2022, with a low PV penetration level are plotted in Figure 2.36 through Figure 2.39, respectively.



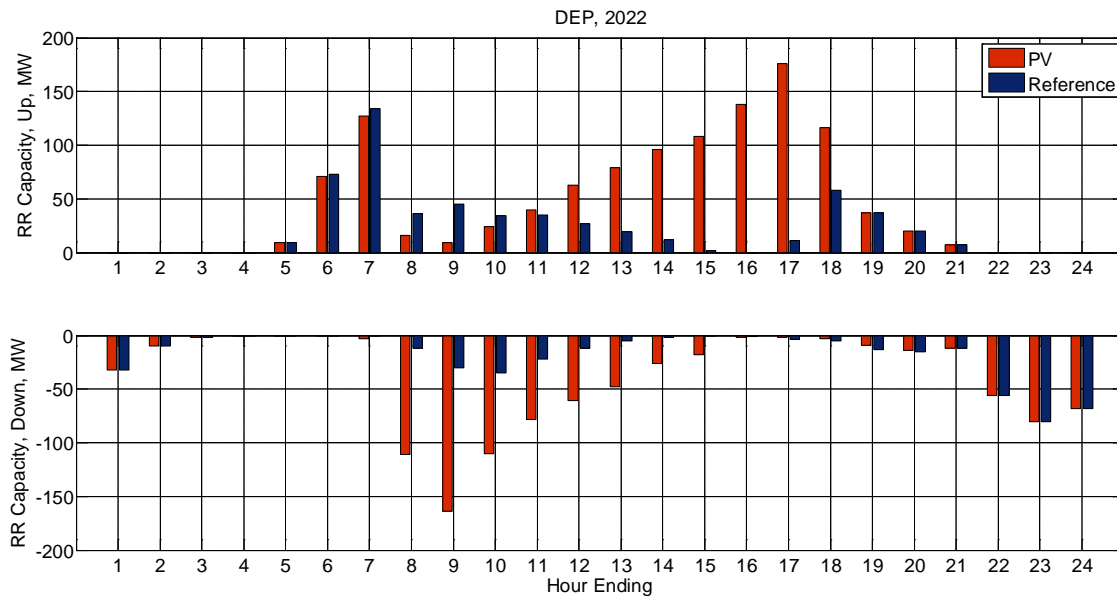
**Figure 2.36.** Regulation Reserve Requirements in DEC for the 2014 Compliance Case



**Figure 2.37.** Regulation Reserve Requirements in DEC for the 2022 High-Penetration Case

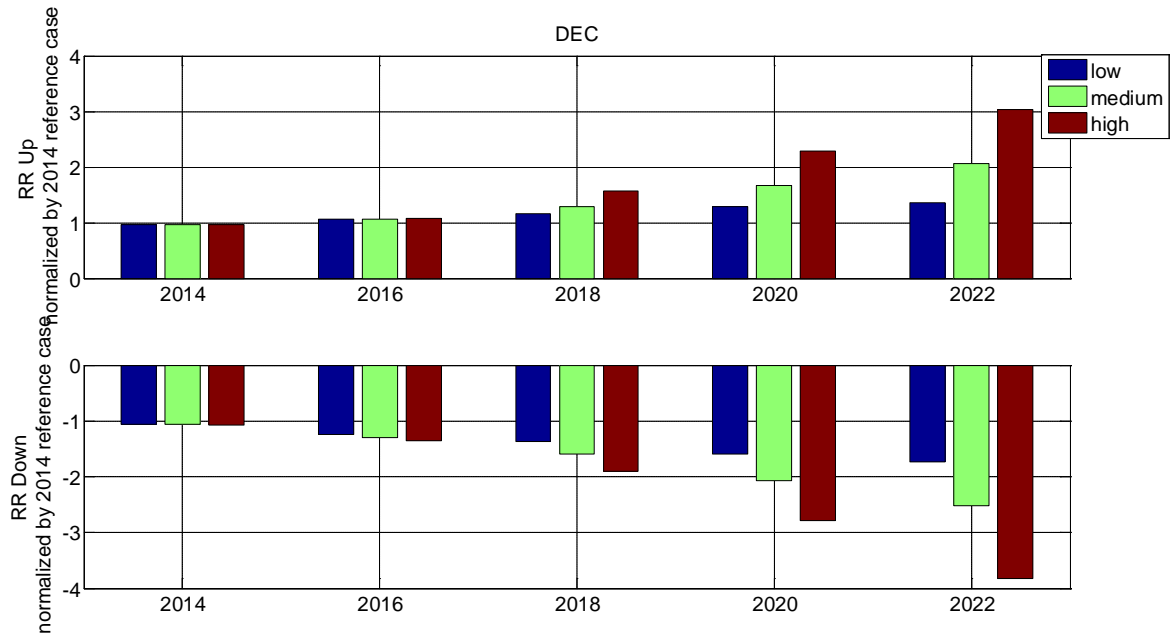


**Figure 2.38.** Regulation Reserve Requirements in DEP for 2014 Compliance Case

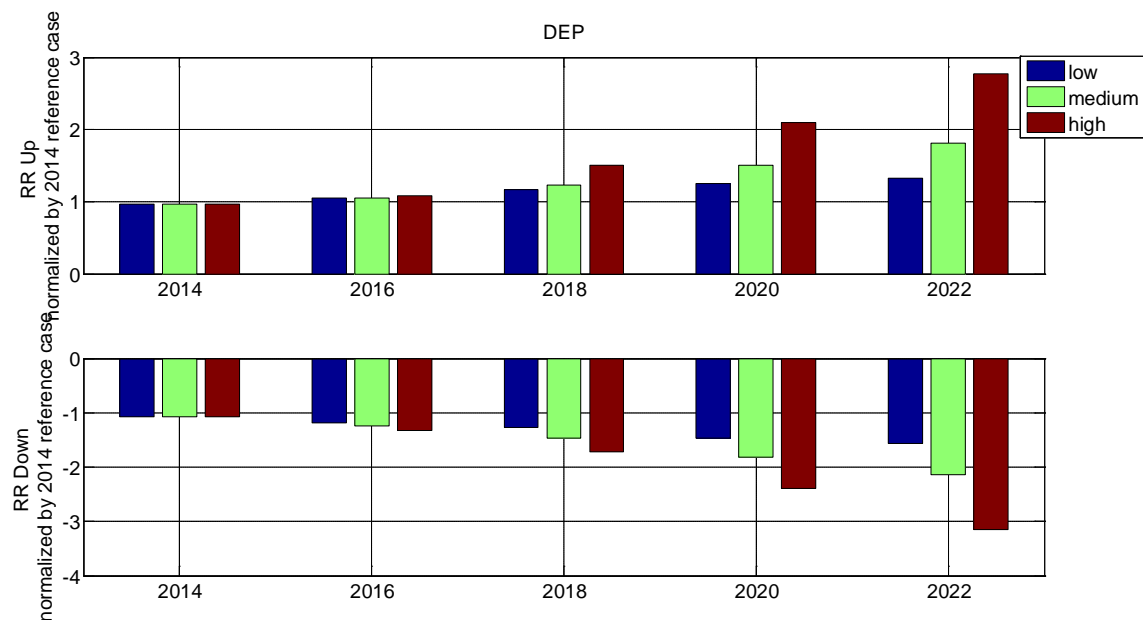


**Figure 2.39.** Regulation Reserve Requirements in DEP for 2022 High-Penetration Case

The trends of RR of the PV cases in DEC and DEP for the 5 study years are depicted in Figure 2.40 and Figure 2.41. Regulation reserves are compared between different cases using the sum of reserve requirements of all hours, and normalized by the values from the 2014 reference case. Results for other cases can be found in Appendix A.



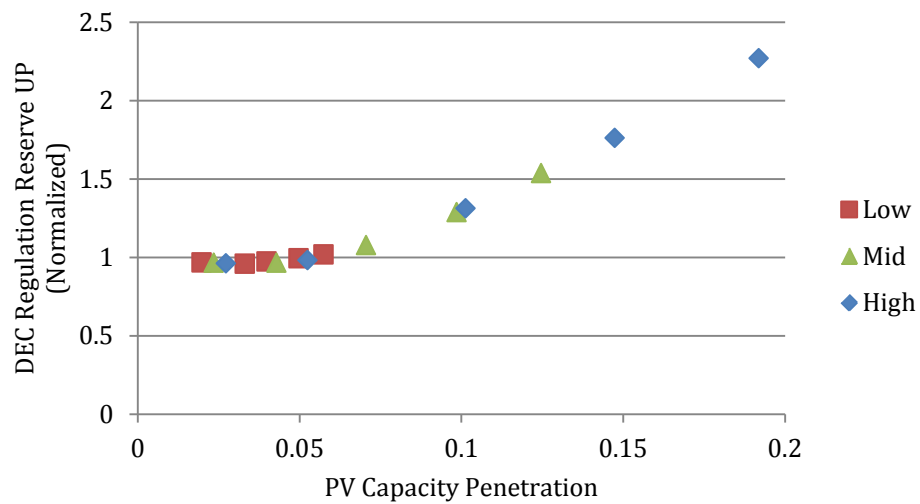
**Figure 2.40.** Trend of the Regulation Reserve Requirements of the PV Cases in DEC



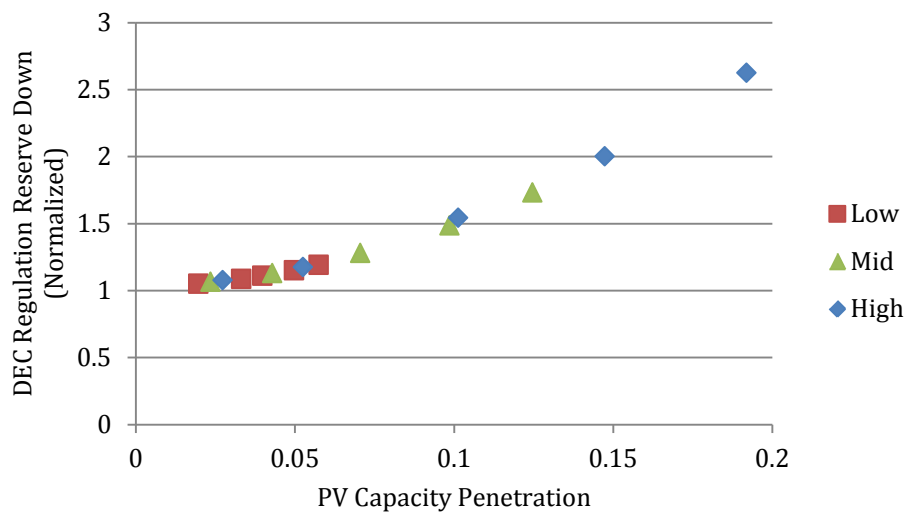
**Figure 2.41.** Trend of Regulation Reserve Requirements of the PV Cases in DEP

The relation between RR requirements and PV penetration rate are shown in Figure 2.42 to Figure 2.45 for DEC and DEP, respectively. The reserve values are normalized using the values of the corresponding reference cases, i.e., reserve requirements without PV. This way the impact of load growth in different study years can be eliminated from the trend plots. Comparing with planning reserve requirements in Figure 2.32 to Figure 2.35, it can be observed that regulation requirements increase much faster. At 20 percent PV capacity penetration level, regulation requirements become 2 to 2.5 times of that of the reference case. Downward regulation requirements increase faster than the upward

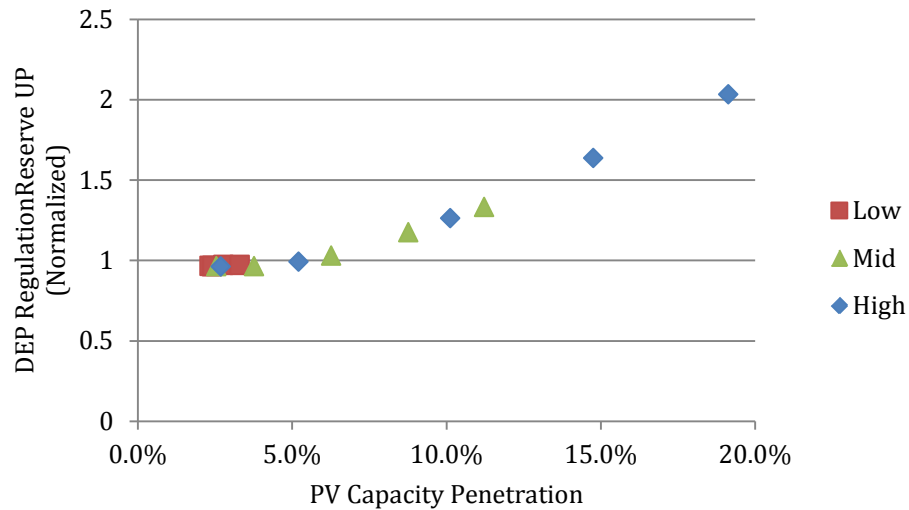
requirements in both the DEC and DEP systems. The data values of reserve requirements for all study cases can be found in Appendix A.



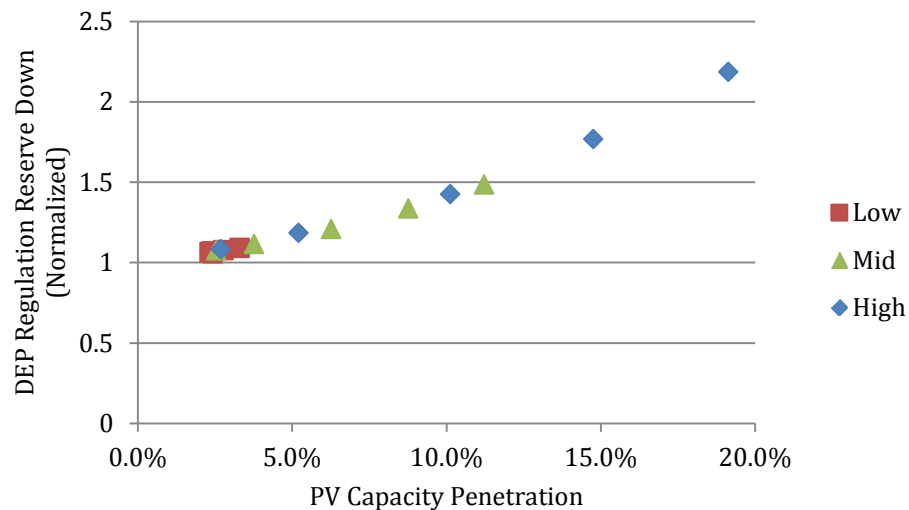
**Figure 2.42.** Regulation Reserve Up of All DEC PV Cases (shown as the ratio between the requirements of PV case and corresponding reference case)



**Figure 2.43.** Regulation Reserve Down of All DEC PV Cases (shown as the ratio between the requirements of PV case and corresponding reference case)



**Figure 2.44.** Regulation Reserve Up of All DEP PV Cases (shown as the ratio between the requirements of PV case and corresponding reference case)

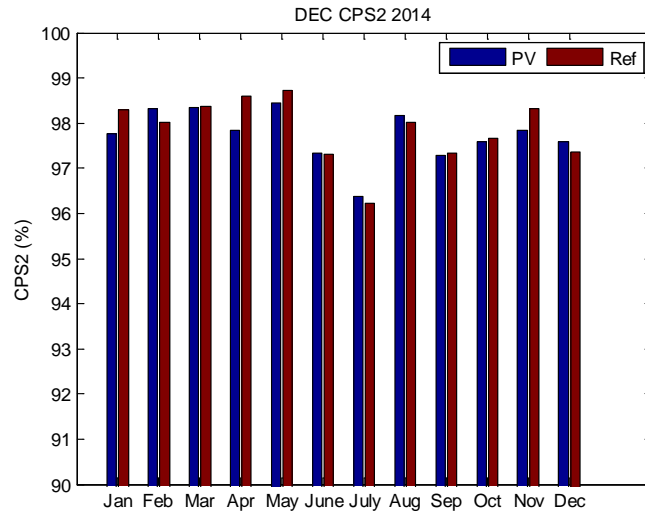


**Figure 2.45.** Regulation Reserve Down of All DEP PV Cases (shown as the ratio between the requirements of PV case and corresponding reference case)

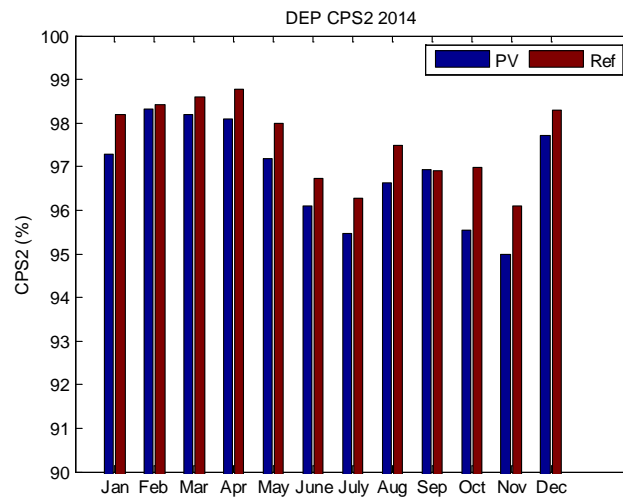
### 2.4.3 Control Performance of PV Cases

One of the goals of the study is to identify potential challenges with meeting NERC control performance standards at high-PV penetration rates. This is measured using CPS2 compliance level as calculated by ESIOS after minute-by-minute dispatch of the system. The desired level of CPS2 scores in the Duke systems based on operating experience is between 95 to 99 percent. In the study, attempts were made to maintain CPS2 within this desired range for both PV and reference cases, by adjusting reserve requirements, peaking unit operating strategy, and AGC control parameters inside ESIOS. The CPS2 of

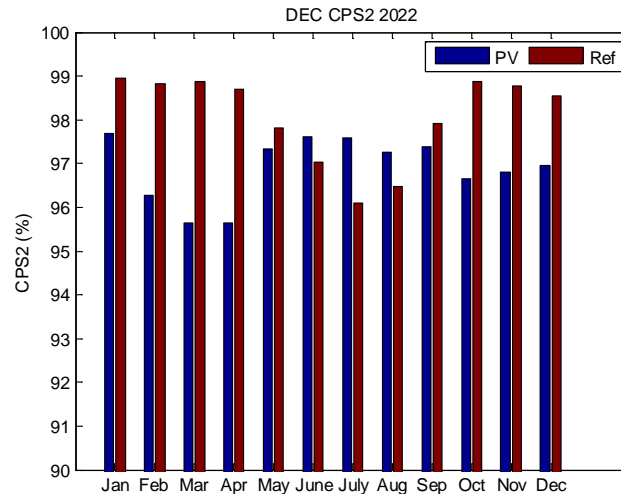
PV and reference cases are also made comparable to allow a fair comparison of production costs. Figure 2.46 to Figure 2.49 are examples of the CPS2 plots for DEC and DEP.



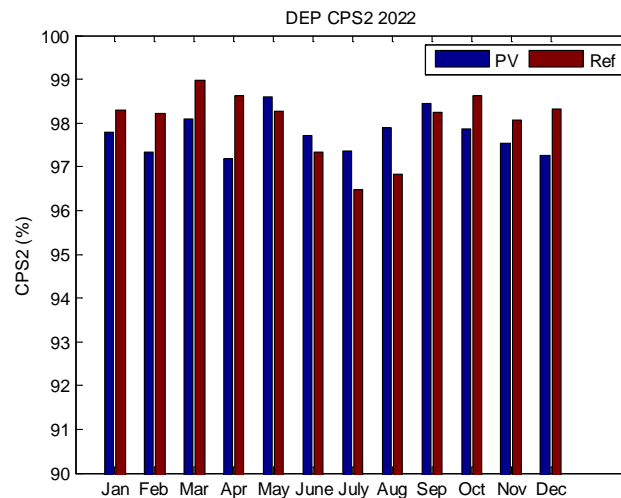
**Figure 2.46.** CPS2 of 2014 Compliance Case, DEC



**Figure 2.47.** CPS2 of 2014 Compliance Case, DEP



**Figure 2.48.** CPS2 of 2022 High-Penetration Case, DEC



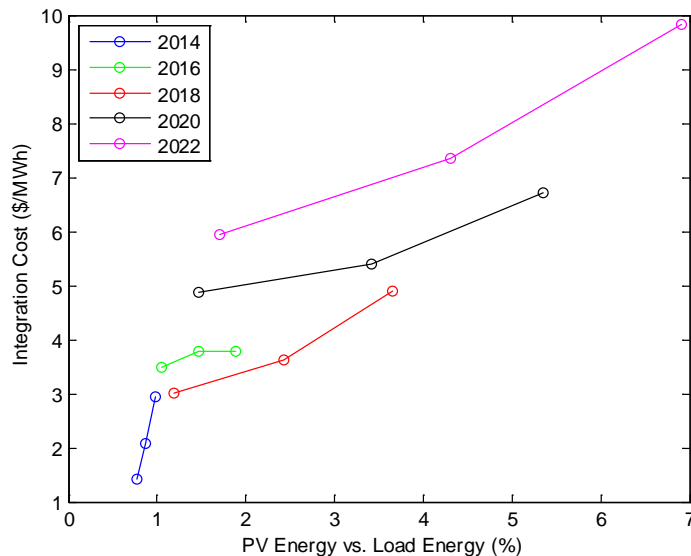
**Figure 2.49.** CPS2 of 2022 High-Penetration Case, DEP

#### 2.4.4 PV Integration Cost

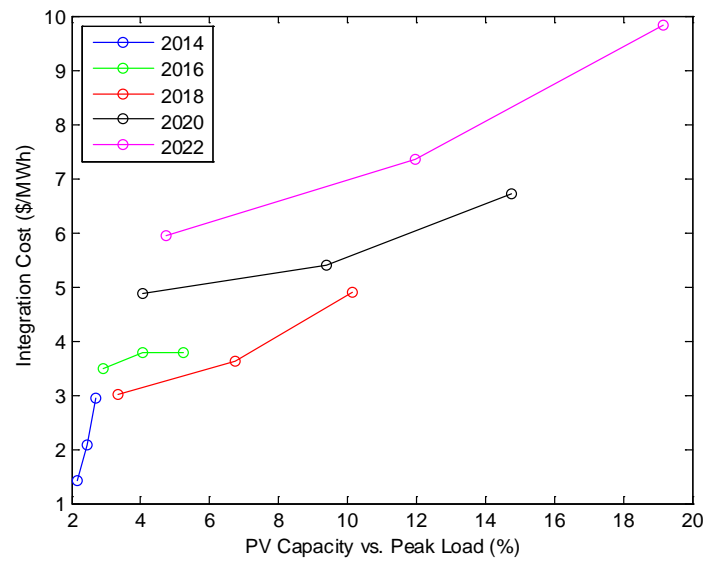
The integration cost captured in the study comes from the additional reserve requirements and intra-hour dispatch of AGC, peaking and PS units, which are adjusted to balance generation and load. The extra wear and tear caused by more startups and output adjustments is not considered. The total production cost in each case is calculated by combining results from GenTrader and ESIOS simulations. The difference between ESIOS and GenTrader costs on AGC, peaking and PS units, which are redispatched in ESIOS based on GenTrader schedule, is added to the GenTrader production cost. The difference between the total production costs of the PV case and the corresponding reference case is the PV integration cost. This cost is then divided by the total PV energy to become the integration cost per MWh of PV energy.

To help understand the results in Figure 2.50 and Figure 2.51, it is worth pointing out that main factors affecting PV integration cost include resource mix and fuel prices, besides PV penetration rate. Because the IRP used to determine resource mixes in the study cases does not change by PV penetration scenarios, the cases in the same study year represent the same resource mix. Differences in PV integration costs for the same PV penetration rate shown on the curves for different years can result from changes on both resource mix and fuel price forecasts.

In the IRP used for the study, 2014 and 2016 cases had the same resource mix, while more efficient combined cycle and peaking units were added to later-year cases. The more efficient units can contribute to the following of system variability at a lower cost. This contributes to the result where 2016 cases show higher integration costs than those of 2018, but are more in line with the trend shown by 2014 cases. Difference in PV integration cost in years 2018 to 2022 results should be attributable to both increases in fuel price forecasts and changes in resource mixes. Figure 2.50 and Figure 2.51 depict the relation between PV integration cost and its energy and capacity penetration rates.

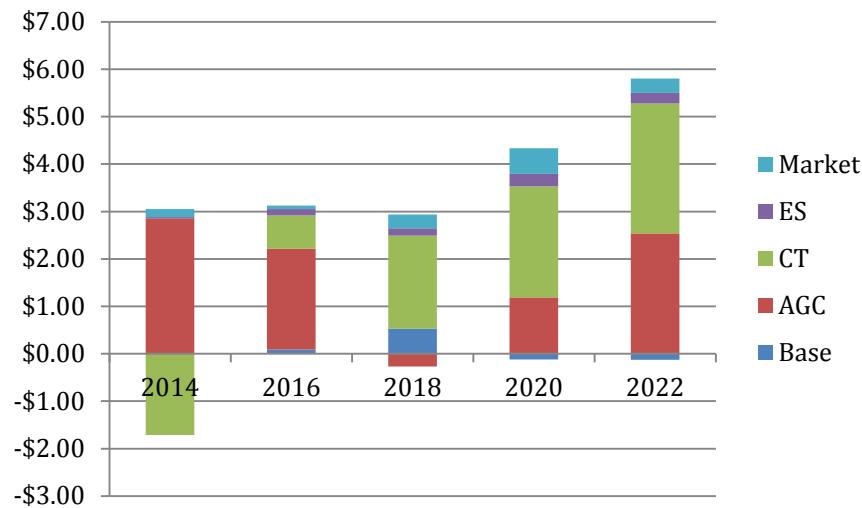


**Figure 2.50.** Integration Cost as a Fraction of PV Energy to Load Energy (MWh)



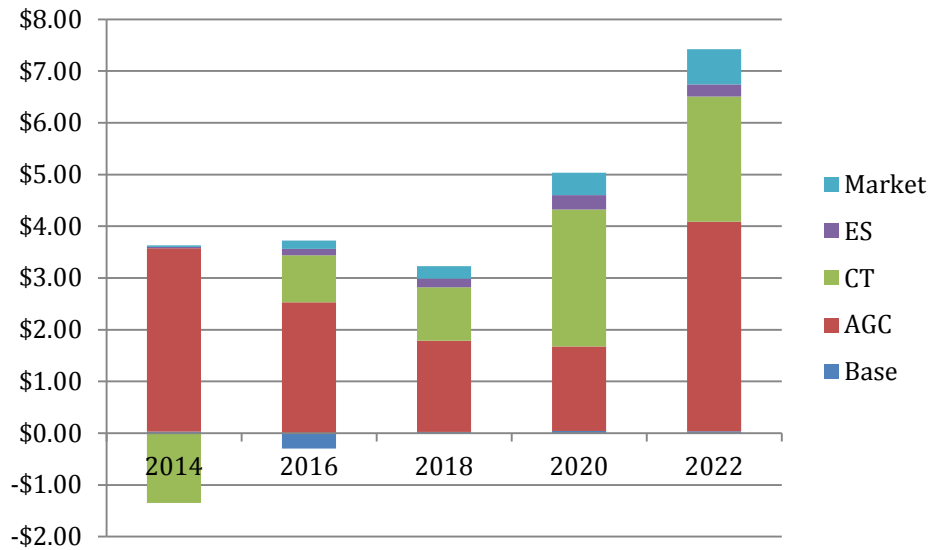
**Figure 2.51.** Integration Cost as a Fraction of PV Capacity to Peak Load (MW)

Figure 2.52 to Figure 2.54 show the integration cost by the type of generation resources.<sup>1</sup> More detailed cost breakdown within each generation type (startup, O&M and fuel cost) can be found in Appendix A.

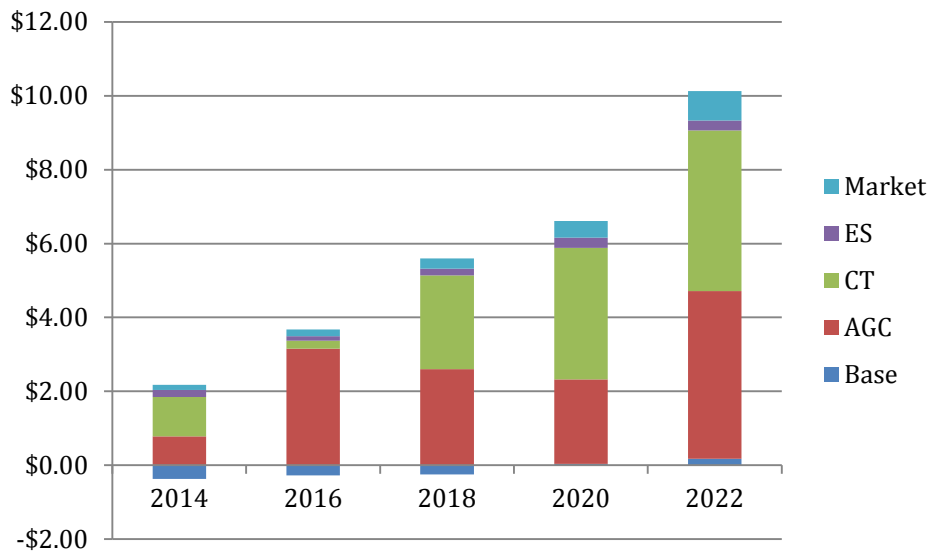


**Figure 2.52.** PV Integration Cost by Generation Type – Compliance Case

<sup>1</sup> The total integration costs shown in the cost breakdown figures are slightly different than the costs in Figure 2.52 (more accurate numbers) because of the differences between GenTrader and ESIOs in the definitions of cost components. When these components are taken from the each program and stacked up directly, small errors are introduced.



**Figure 2.53.** PV Integration Cost by Generation Type – Mid-Penetration Case

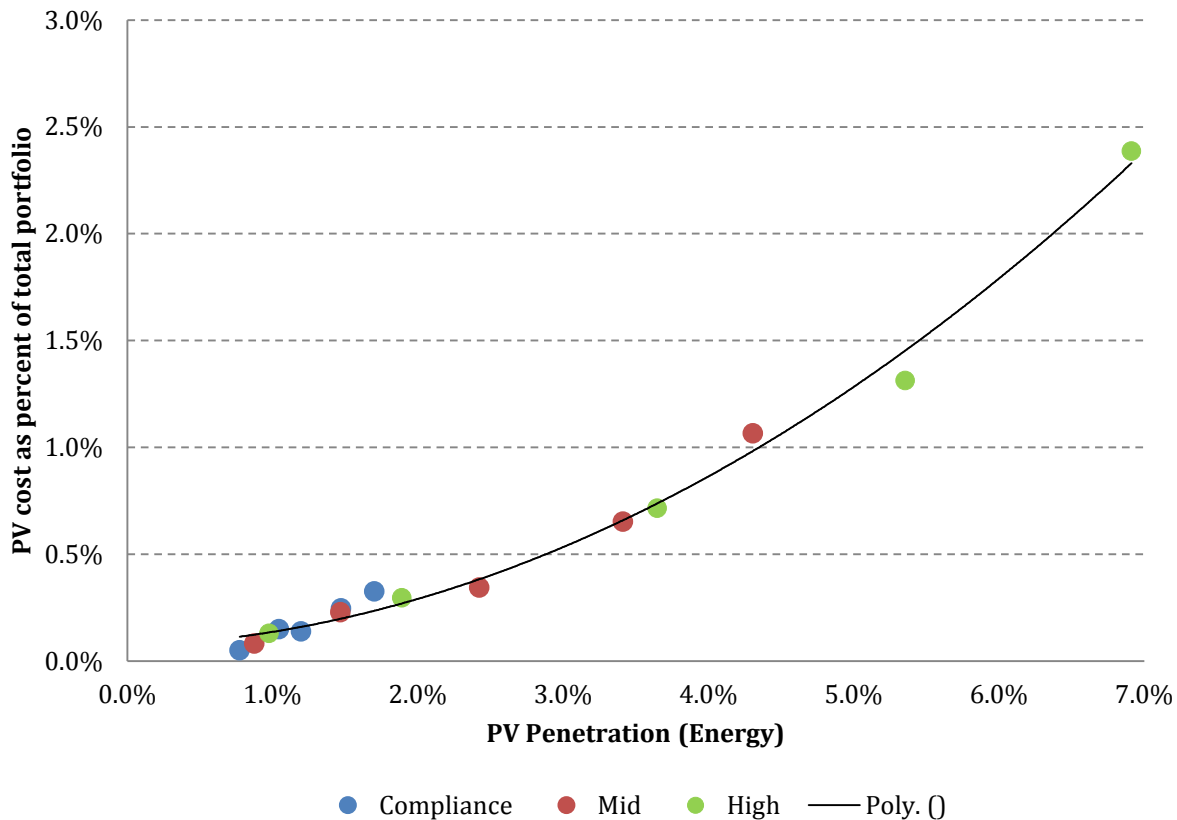


**Figure 2.54.** PV Integration Cost by Generation Type – High-Penetration Case

As mentioned above, fuel is significant part of PV integration cost, and the upward fuel price forecasts reflect themselves on the penetration cost curves in Figure 2.50 and Figure 2.51. Similar levels of PV penetration cost more as the penetration date ranges further into the future. Effort was made to remove this bias by looking at the integration cost as percentage of the total portfolio cost. This way the impact of upward fuel price forecast is eliminated since the fuel price impacts both the nominator and denominator at the same ratio. The resulting curve is fairly smooth and can be approximated by a simple second degree polynomial as shown in Figure 2.55.

The polynomial equation below captures the relationship between PV penetration and cost of integration with less than 1 percent error ( $R^2=0.9912$ ) where Y is the PV integration cost as percent of total portfolio cost and X is the PV generation as percent of total system generation:

$$Y = 4.4107 * X^2 + (0.0219 * X) + 0.0007 \quad (5)$$

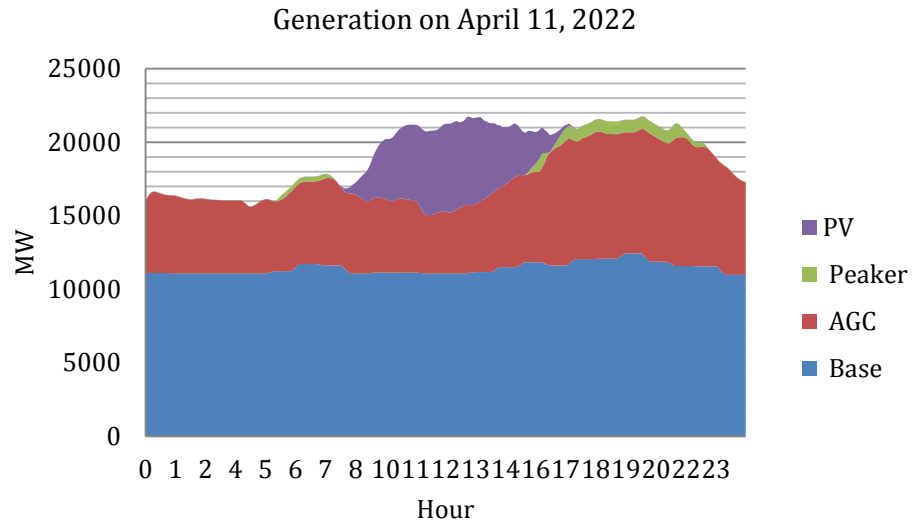


**Figure 2.55.** Relationship between PV Integration Cost as Percent of Total Portfolio Cost and PV Generation as Percent of Total System Generation<sup>1</sup>

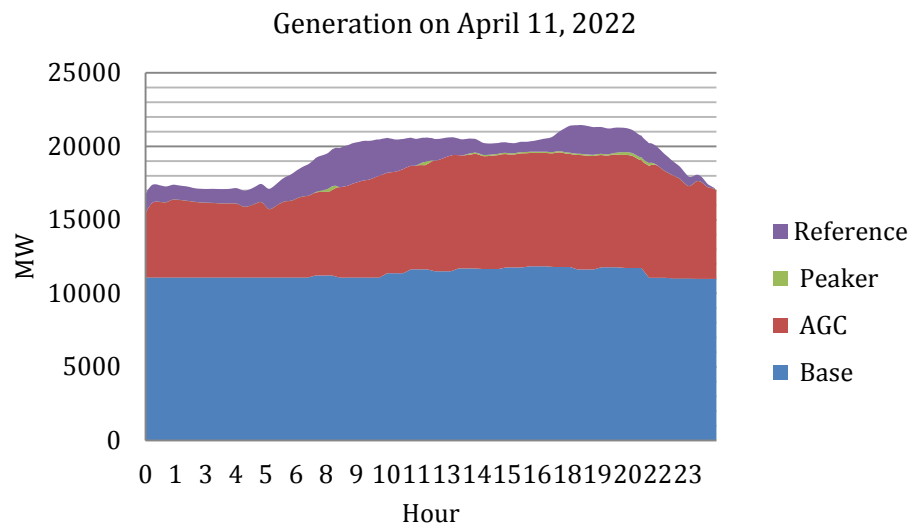
PV integration results in needs of additional reserves and more cycling of conventional units and thus incurs cost due to efficiency loss and increase startup and O&M costs, as discussed in Section 2.2.3.1. One day with high-PV production in the 2022 high-penetration case was selected to illustrate PV energy's impact on the dispatch of conventional units. The results by generator functions (base load, AGC and peaking) are shown in Figure 2.56 and Figure 2.57 for comparison between the PV and reference cases.

Similar comparison by fuel types (nuclear, coal and natural gas) are shown in Figure 2.58 and Figure 2.59. Note that AGC units consist of both coal and natural gas-fired units. Resource types other than those shown in the plots include market transactions and diesel and oil fuels, which are relatively small in energy contribution. Pumped storage in the DEC system was also left out deliberately to avoid overlapping the areas of other generators when the PS is in pumping mode and showing as negative generation.

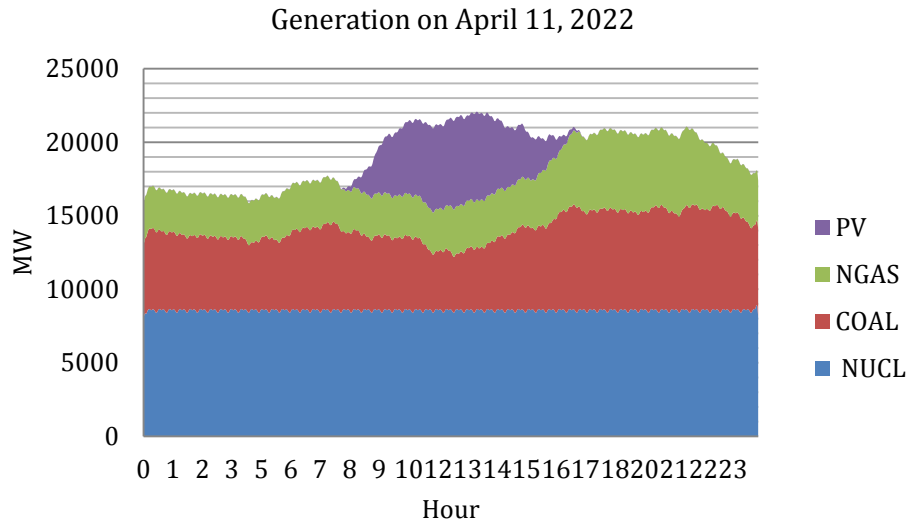
<sup>1</sup> Contributed by Pedram Mohseni with Duke Energy.



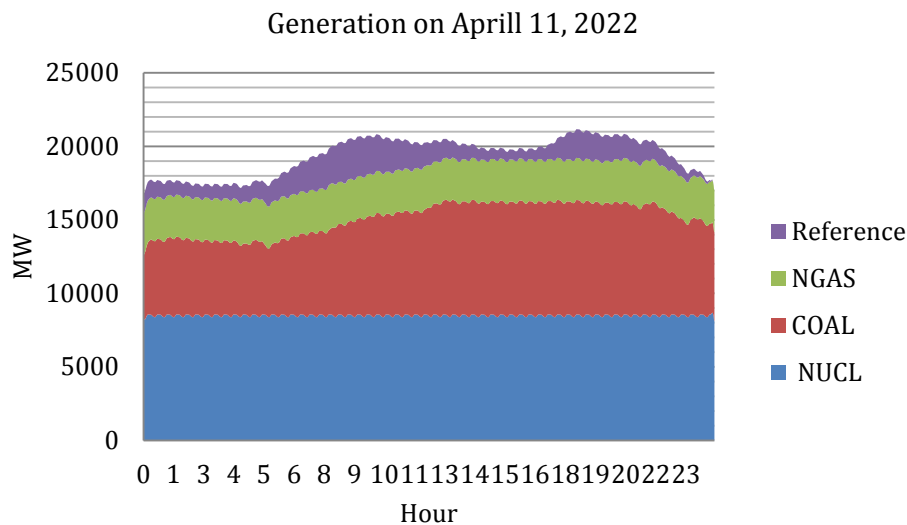
**Figure 2.56.** Combined DEC and DEP Generation Dispatch in the High-PV Case by Functions



**Figure 2.57.** Combined DEC and DEP Generation Dispatch in the High Reference Case by Functions



**Figure 2.58.** Combined DEC and DEP Generation Dispatch in the High-PV Case by Fuel Types

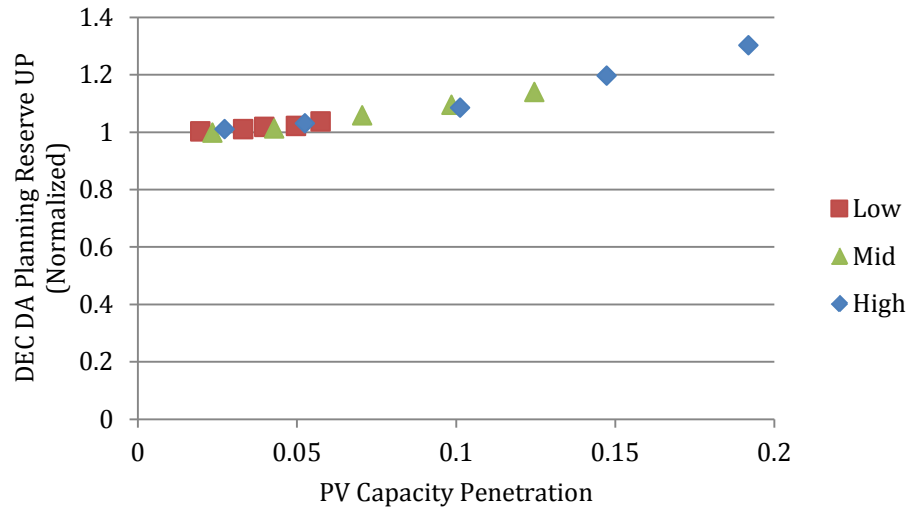


**Figure 2.59.** Combined DEC and DEP Generation Dispatch in the High Reference Case by Fuel Types

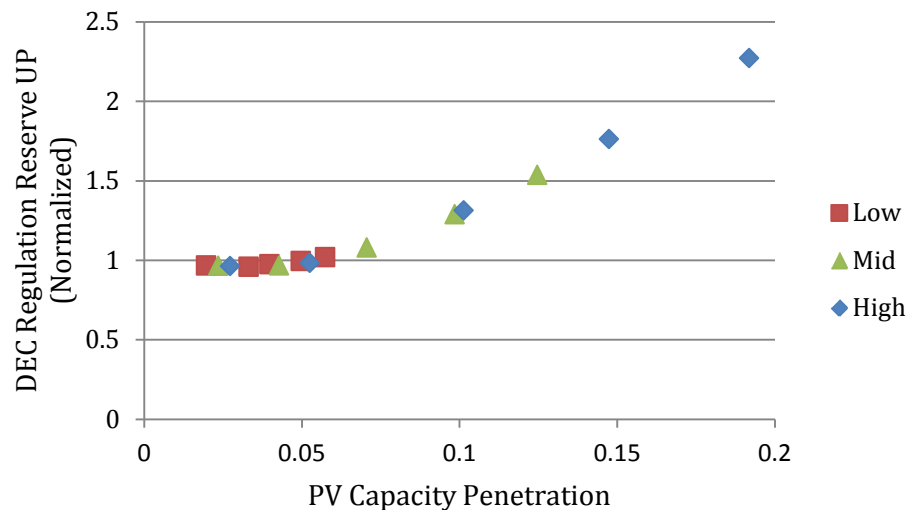
## 2.5 Generation Study Findings and Discussions

### 2.5.1 Study Findings

The study found that system net-load variability increases with PV penetration. As a result, with PV penetration increasing to 20 percent of peak load in the integration cases, system DA planning reserve requirements (not including contingency reserve) increase to 130 percent, and RR requirements increase to 240 percent of the values without PV (reference cases). An illustration of reserve requirements trend can be found in Figure 2.32 and Figure 2.42, and for convenience of readers, they are plotted here again Figure 2.60 and Figure 2.61.



**Figure 2.60.** DA Planning Reserve Up of All DEC PV cases (shown as the ratio between the requirements of PV case and corresponding reference case)

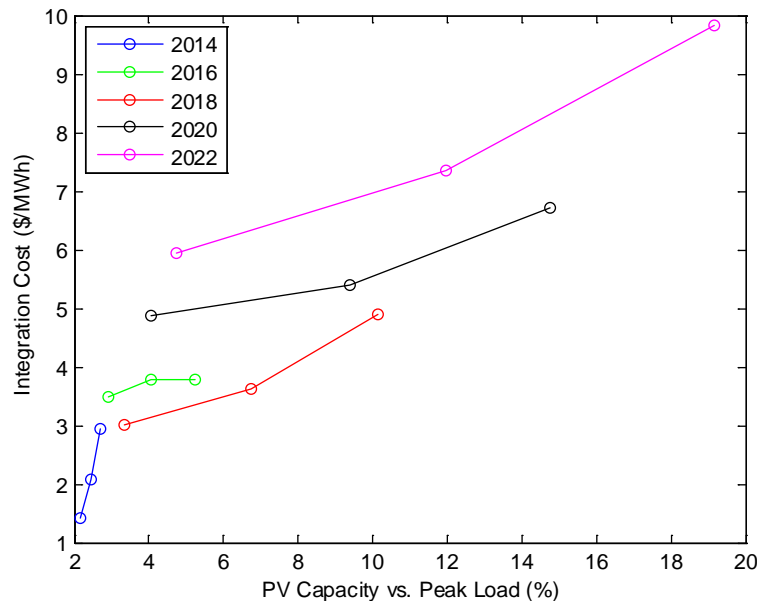


**Figure 2.61.** Regulation Reserve Up of All DEC PV cases (shown as the ratio between the requirements of PV case and corresponding reference case)

The Duke Energy system was able to maintain reliable operations in dispatch simulations, evaluated in terms of meeting ancillary service requirements and the target compliance level with NERC CPS, with the caveat that contingencies were not modeled. Under the study conditions, Duke Energy's generation fleet showed to be capable of accommodating PV with an installation capacity of up to 6800 MW, the highest level investigated in this study.

Simulation results indicate PV integration imposes additional costs on the conventional generating fleet, resulting from the need of additional reserves and cycling of conventional generators to compensate for PV variability. Although total system production cost decreases at higher PV penetration rates (when cost of PV energy is not included), the unit cost for conventional generation to serve the same amount of

energy increases with each increase in PV on the system. Based on the load, resources, fuel prices and other assumptions made in the study, PV incurs an integration cost that ranges from \$1.43 to \$9.82 per MWh of PV energy (Figure 2.62, a duplicate of Figure 2.51), in comparison with reference generation. This result is in line with other similar studies [3][4]. The result also exhibits a trend of increasing unit PV integration cost at successively higher PV levels. Note that this conclusion does not incorporate the results from the study of losses on the transmission and distribution system.



**Figure 2.62.** PV Integration Cost as a Fraction of PV Capacity to Peak Load (MW)

## 2.5.2 Discussions on Limitations and Future Studies

It should be noted that projected PV system sizes and locations, future load growth, resource mix and fuel prices, are a few assumptions with great impact on study results. Although they were carefully made with the best data available, future system conditions will be different. The sensitivity of PV integration cost to PV locations, fuel prices, and even thermal generation build-out should be investigated, in addition to the defined scenarios, to fully understand the impact of these assumptions on study results.

Of similar importance to the above assumptions are the simulation models and their parameters, such as PV production, DA and real-time forecasts, unit commitment and economic dispatch, AGC, and operator actions. New study tools and procedures to model PV production and system operations were applied in the study. In some places necessary simplifications were made to produce the results timely, while in other cases reasonable improvements to operational procedures were modeled to deal with high-PV penetration rates.

For example, PV fleet forecasts for DEC and DEP in DA and real time were incorporated in reserve requirements calculations, which do not yet exist in real practice. Unit commitment was performed using actual load and PV production, instead of forecasted values as what happens in reality. Dynamic operating reserves that vary with hour of the day were applied in the unit commitment process. These models and parameters should be checked against real-world data for effectiveness as operation experience at significant PV penetration rates is accumulated over time.

In summary, refined model assumptions, additional validation of modeling tools, and improved study procedure should be attempted in future studies. Contingencies caused by conventional resources and affected by PV systems should be considered. Frequency response of the system at high-PV penetration rate, which was left out of the scope of this study, should also be investigated.

The same set of assumptions and models which affect study results significantly also point to the directions of operation and technology improvements for a smooth transition toward the high-PV energy mix. The improvements can be categorized into the following aspects:

1. *Increase fleet flexibility* – More flexible and efficient fleet tends to have a lower PV integration cost and better control performance, which should be taken into consideration in new generation build-out. Storage and demand response are other effective approaches to meet such goals. Fleet flexibility can also be improved by coordinating the balancing operations of DEC and DEP.
2. *Reduce uncertainty and variability* – Incorporating PV forecast into operation processes and improving forecast accuracy can directly reduce operation uncertainty. Aggregation of PV production in the two areas through BA coordination increases diversity and reduces total reserve requirements, which further helps lowering PV integration cost. Research is going on to reduce additional reserve requirements induced by PV variability through controlling power production ramp rate and providing regulation service by PV inverters.

Efforts to make the above improvements are certainly not free. Nonetheless, the attempts should be worthy if their costs are a fraction of the potential PV integration costs. These improvement solutions need to be assessed through future studies.

## 3.0 Transmission Study

### 3.1 Scope

The objective of this exercise was to study the impact of 1197 MWs installed AC nameplate capacity of distributed PV on the transmission system. Specifically, the focus was on the sub-transmission system (44-kV and 100-kV) to determine the potential for over-voltage that violates operational limits. The study also looked at impacts on transmission real power losses and reactive power consumption. The study focus was on the DEC system because the analytic tools used for the study are currently used on the DEC system but not the DEP system. Nevertheless, the general findings should apply to the DEP system as well.

The 1197 MWs of distributed solar PV represents the compliance case developed in the generation study. Based on the current interconnection queue and existing operating solar PV, this level of penetration should provide a reasonable first-view of impacts on the transmission system.

### 3.2 Methodology

Four seasonal models were created, a summer peak load day, a spring light load day, a fall light load day, and a winter light load day. A winter peak case was not developed as the DEC system winter peak occurs after sunset and before sunrise. This approach, to use four representative days for each season, is common among transmission planners at Duke and many other utilities. More robust modeling approaches may need to be developed to better evaluate the impacts of significant penetrations of DG.

For each season two power flow models were created, first a base power flow model without PV generation then a second power flow model with PV generation. The power flow models are full nodal models for the Eastern Interconnection for year 2012. The net interchange of the Duke system with neighboring balancing authorities was kept constant in both cases; therefore, selected Duke Energy units were de-committed and/or the power generated was reduced to compensate for the generation increase in the power flow cases with PV (i.e., rebalance generation to load).

### 3.3 Data Inputs

For each power flow model, transmission loads were coincident metered loads for all delivery substations at the selected hour of simulation in 2012.

Assuming solar generation requirements for Duke Energy will reach 1197 MW by 2022, both distribution and transmission studies analyze the impacts of 1197 MW of solar that is assumed to be mainly installed on the distribution grid. To do this, the existing connected sites as well as the pending sites in the interconnection queue were evaluated. An algorithm was created to prorate the difference between the existing known solar sites by county and the required 1197 MW. After the solar was allocated to each county the plan was reviewed to verify there was no foreseeable reason why the allocation was not possible.

The second step was to allocate the solar in each county down to the individual substation and circuit. A spreadsheet with all of the substations and circuits by county was created. First, all of the existing connected solar sites and pending solar sites were allocated to the correct circuit. This accounted for 550 MW with system sizes ranging from 750 kW to 5 MW.

To allocate the remaining 647 MW, existing data and staff expertise was used to determine what system sizes should be connected to the individual circuits in each county. For example, in Mecklenburg County the majority of the interconnection requests are small residential roof top units with a few scattered 500 kW or smaller commercial systems. Residential circuits were assumed to have small solar systems, 2-4 kW, allocated across the circuit whereas circuits that are more commercial in character were assumed to have 100 kW – 500 kW size systems. Depending on the type of load on the circuit, PV installations were added by distributing small scale solar along the main trunk line (residential) or in a smaller number of larger installations (commercial). This process was continued until all 647 MW was allocated to the correct counties.

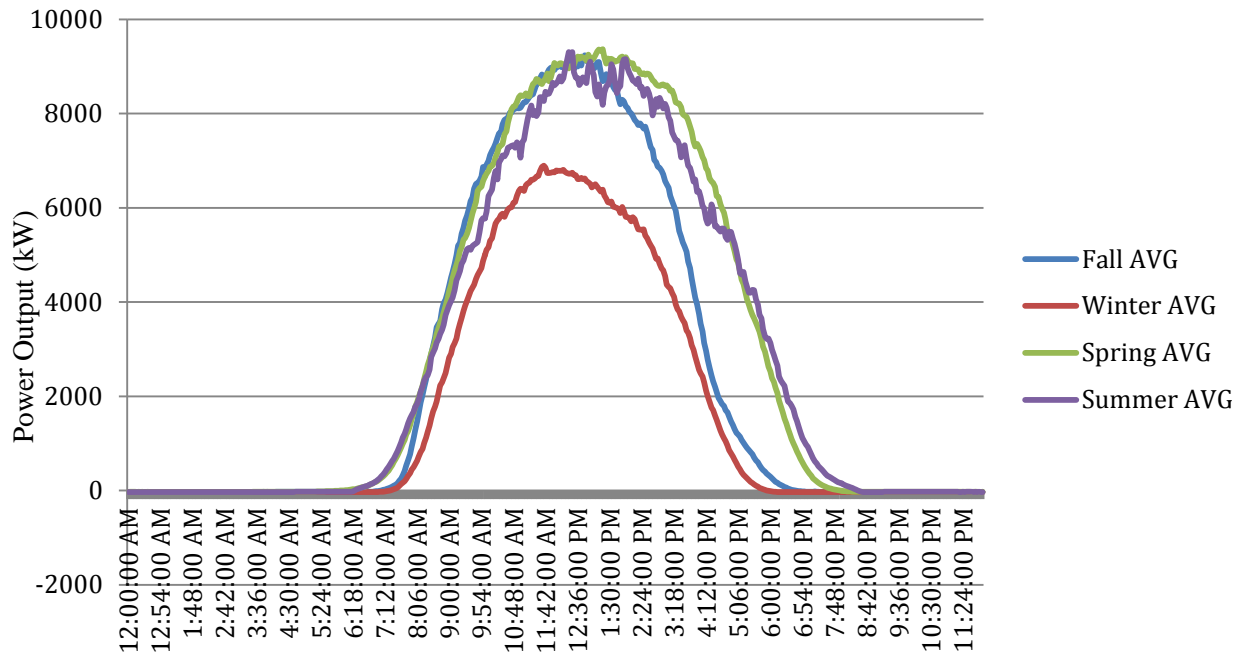
After applying the allocation, 473 out of 2545 feeders and 262 out of 661 substations had DG added to the circuit, varying between 2 and 30,000 kVA of solar DG installed. For the purpose of this study, solar sites were distributed along the backbone section of all circuits and not along tap lines.

Solar generation is both intermittent and variable; therefore 15 minute averaged meter data does not provide the granularity needed to fully understand operational impacts at the transmission and distribution level. At the time of the study, there were only nine existing solar sites on the Duke system in operation with two-way communication installed. Electronic re-closers, circuit breakers equipped with a mechanism that can automatically close the breaker after it has been opened due to a fault, were installed at these sites as a protection device to allow immediate capability to disconnect the site from the distribution grid. As an added bonus, these devices also provide real-time data. The electronic re-closers provided the study with 3-minute averaged production data. Only seven of the nine solar sites had been in production for over a year therefore data from those seven were used to create a representative solar production curve and the power factor curve by season. The seven sites total 14.7 MW in inverter capacity. Covariance analysis was completed and showed that the sites are all 72 to 92 percent correlated despite some being over 80 miles apart.

To create the season production curves and power factor curves the data for all the sites was separated into the following seasons:

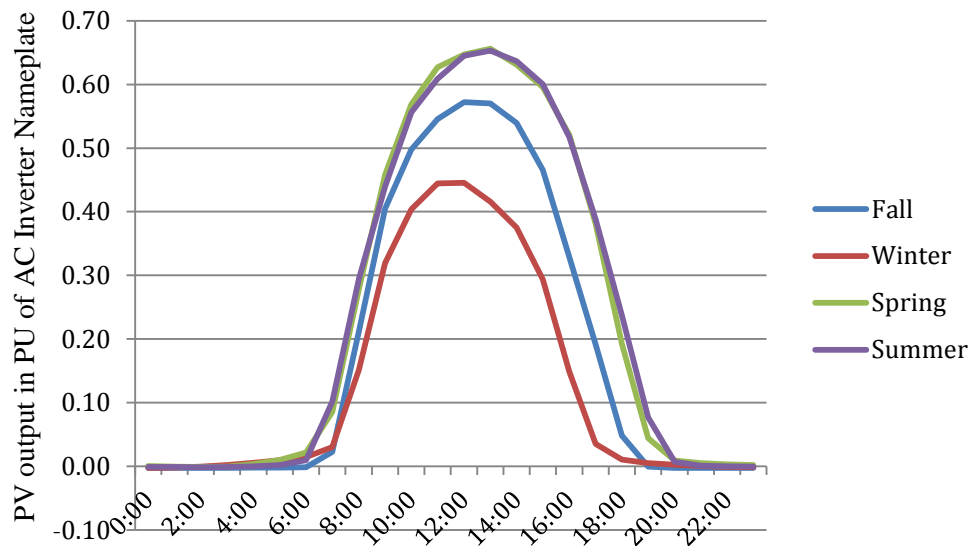
- Spring – March 2013, April 2013, May 2013
- Summer – June 1-17 2013, June 18-30 2012, July 2012, August 2012
- Fall – September 2012, October 2012, November 2012
- Winter – December 2012, January 2013, February 2013.

The daily 3-minute data from each site was then averaged to create the simulation production curve for every 3 minute during the day. Figure 3.1 shows the chart for the averaged seasonal production curves based on the seven solar PV sites referenced above. The summer curve is not as smooth as the spring, winter or fall curve due to seasonal showers and thunderstorms.



**Figure 3.1.** Averaged Seasonal Production Curves of Seven Solar Sites

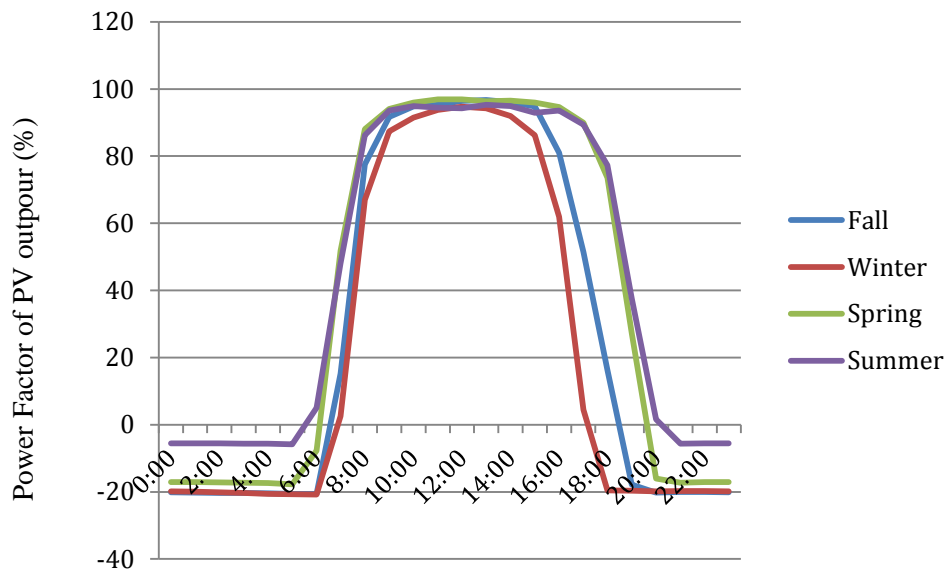
The 3-minute data was then averaged over each hour and divided by the AC Inverter nameplate capacity for each site to develop the PV capacity curve as shown in Figure 3.2. It is important to note that this “representative” curve is an average across the season. As a result, the summer peak output is approximately 65 percent of nameplate. This curve was used throughout the transmission study. Accordingly, statements about total installed capacity reflect 65 percent of that capacity. In other words, full nameplate capacity was not evaluated; therefore, conclusions about impacts at 100 percent of nameplate capacity cannot be drawn from study results.



**Figure 3.2.** Measured PV Output on Average in PU of AC Inverter Nameplate Value

PV sites in the distribution system were aggregated to the nearest transmission substation buses in the power flow model and tagged as load zone PV. In each power flow case with PV, the power output for the selected simulated hour was aggregated at the substation level and it was modeled as negative load supplying both active and reactive power operating at 0.97 lagging power factor, i.e., the aggregated PV will supply reactive power equals to 25 percent of its real power output. The choice of this power factor is based on historical recorded measurements of current selected distributed PV in the DEC system. It should be noted that interconnection requirements for the state of North Carolina allow power factor to range between 0.95 lagging to 0.95 leading. It is also worth noting that advanced inverters and controls can manage reactive power such that this is not an issue. However, none of these were among the systems used for this study.

The power factor profile shown in Figure 3.3 was also created using the 3-minute data from the sites. It is important to note, however, to maximize production several developers are installing additional panels to increase production as well as dynamically changing the power factor to maximize energy production (kWh) while still maintaining an average power factor required in the interconnection agreement.



**Figure 3.3.** Measured PV Power Factor at Current Connected Solar Sites

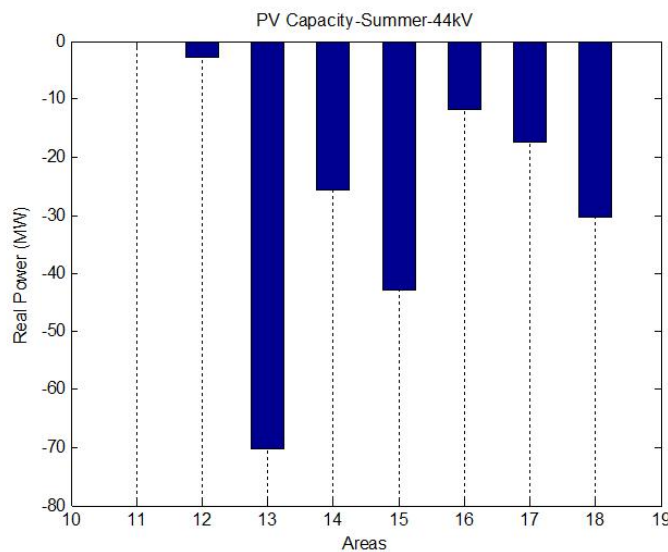
The following sections cover the power flow simulations that were performed to study system bus voltage regulation, and transmission losses. Comparisons of capacitor and reactor banks switching in different areas of Duke Energy transmission system are given in Appendix B.

## 3.4 Results

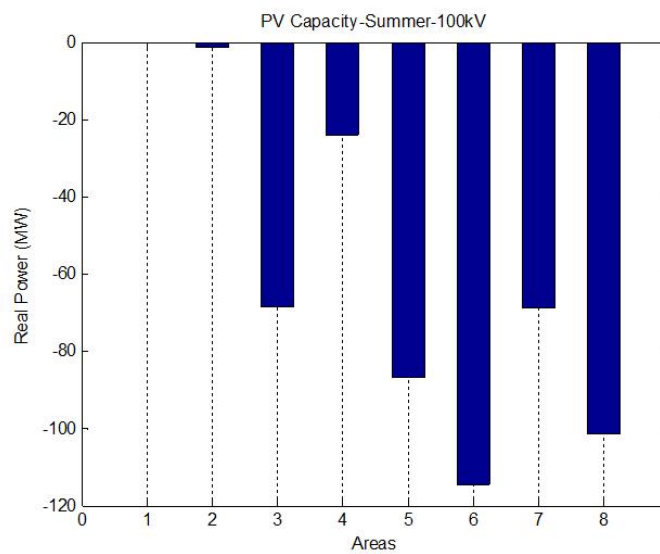
### 3.4.1 Summer Peak Hour Load Case

#### 3.4.1.1 2012 Summer Peak Model Details

The 2012 summer peak model was created using substation loads from July 26, 2012 at 5:00 PM, with total load of 20,107 MW. PV was modeled by adding 671 MWs of distributed PV to the summer base case and reducing conventional generation by an equal amount. The PV generation output at each system load bus was calculated by multiplying the installed PV capacity at each site by the average summer PV capacity factor for 4:00 P.M. and 5:00 P.M. The distribution of PV output at different areas of the 44-kV and 100-kV systems are given in Figure 3.4 and Figure 3.5, respectively.



**Figure 3.4.** PV Output in the Summer Case at Different Areas in the 44-kV Sub-Transmission

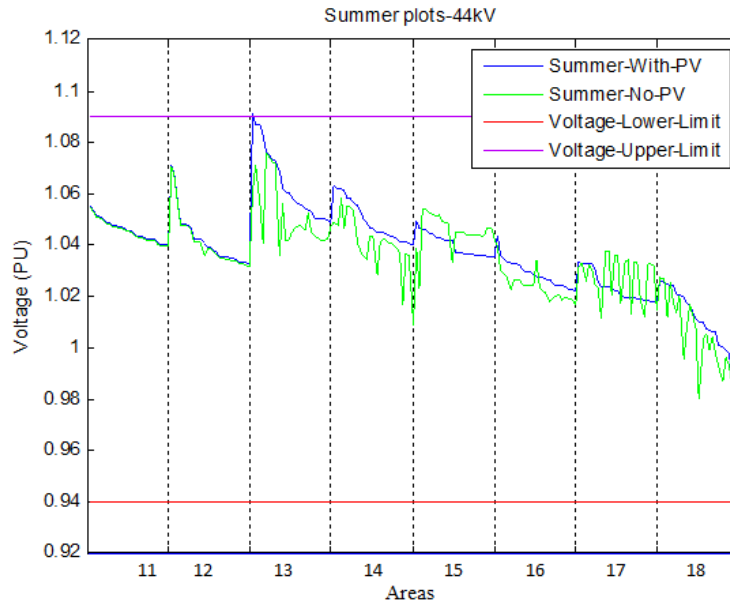


**Figure 3.5.** PV Output in the Summer Case at Different Areas in the 100-kV Sub-Transmission

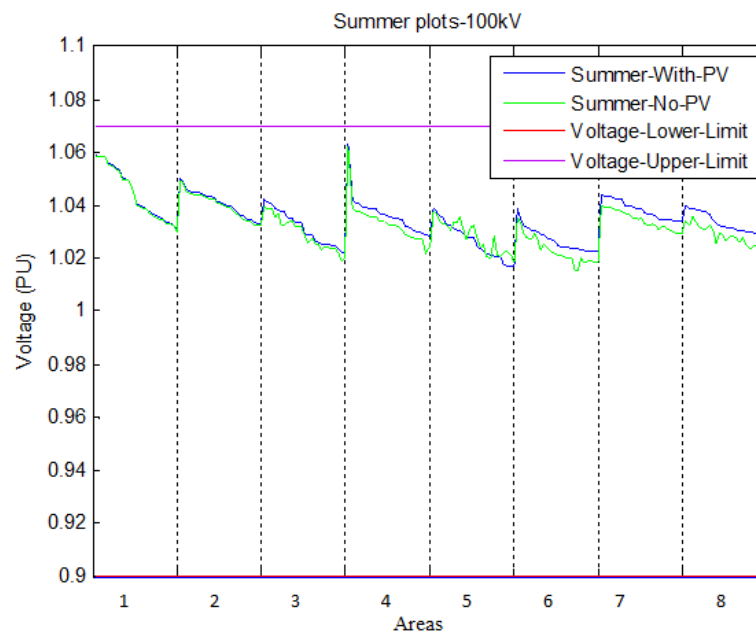
### 3.4.1.2 Summer Case- Voltage Profiles

Highest observed voltage magnitudes in the PV case at different areas of the 44-kV and 100-kV systems are shown in Figure 3.6 and Figure 3.7, respectively. Each segment in the graph shows voltage profiles at selected 25 buses with the highest voltage in the corresponding area.

No significant increase in voltage magnitudes were found between the 2012 summer base model without PV and the summer PV model. Loading and voltage regulation of the transmission system under normal operation were found to be within planning guidelines for both.

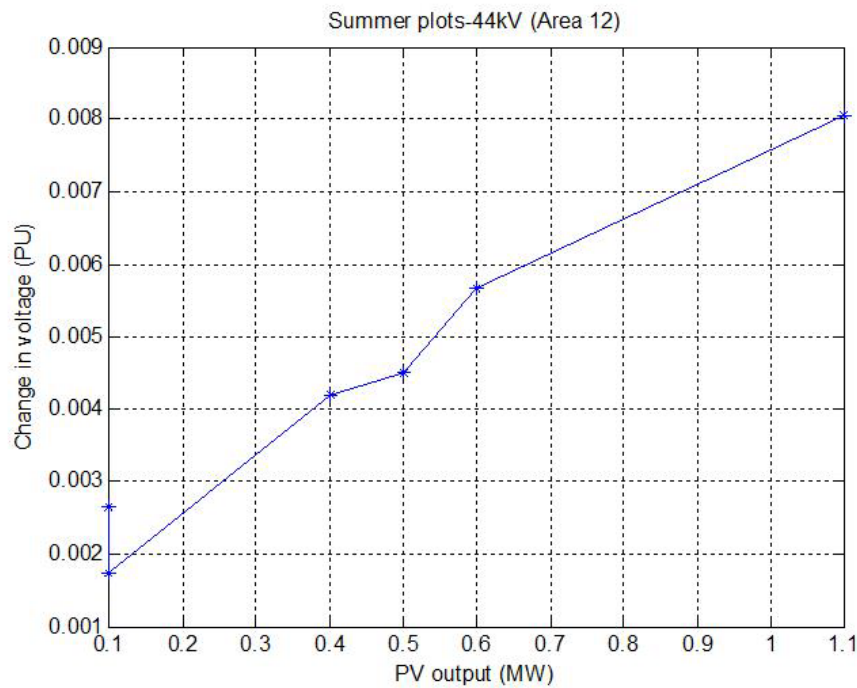


**Figure 3.6.** Highest Voltage Profiles – Summer Case 44-kV Sub-Tranmission

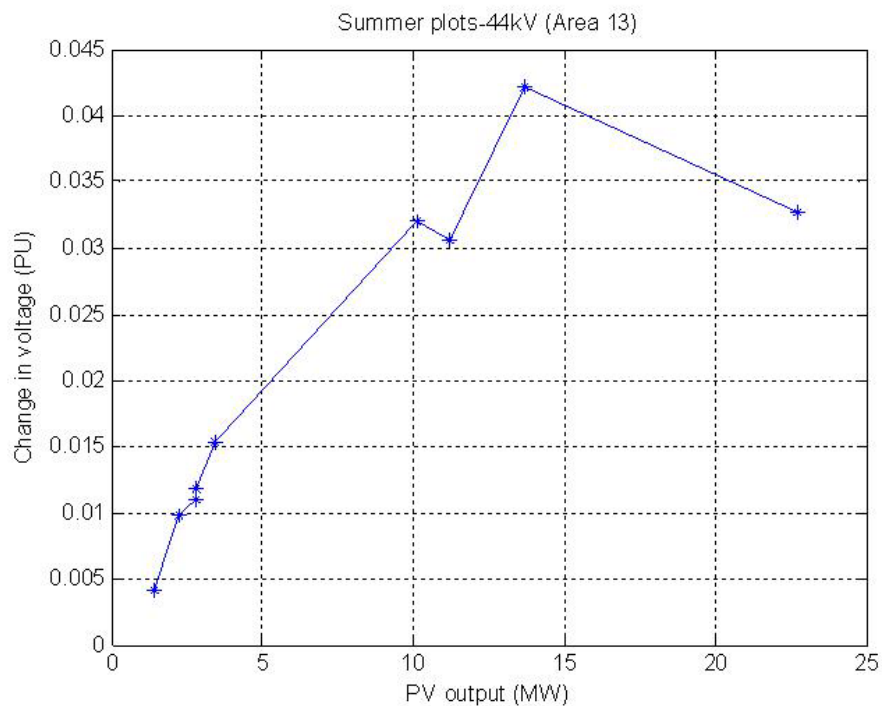


**Figure 3.7.** Highest Voltage Profiles – Summer Case 100-kV Sub-Tranmission

The relationship between the increase in the bus voltage in areas 12 and 13 of the 44-kV system and the corresponding PV output at the same bus is shown in Figure 3.8 and Figure 3.9.



**Figure 3.8.** Relationship between the Increase in Bus Voltage in Area 12 of the 44-kV System versus PV Output at the Corresponding Bus in the Summer Case

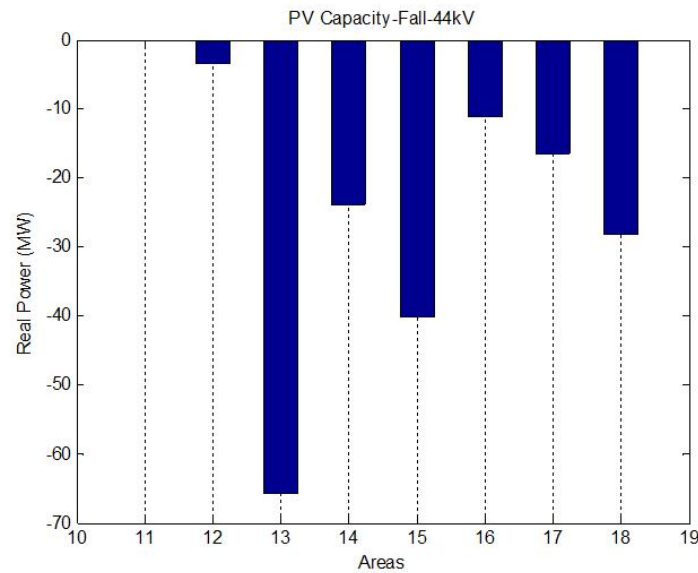


**Figure 3.9.** Relationship between the increase in Bus Voltage in Area 13 of the 44-kV System versus PV Output at the Corresponding Bus in the Summer Case

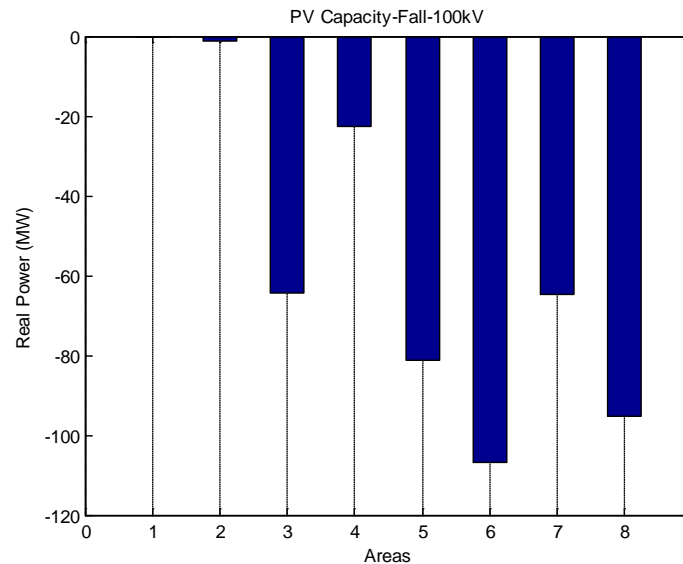
### 3.4.2 Fall Light Hour Load Case

#### 3.4.2.1 2012 Fall Light Load Model Details

The fall light load day model was created using substation loads from October 21, 2012 at 11:00 A.M. with total load of 9,166 MW. The corresponding PV model was created by adding 630 MWs of distributed PV to the fall base case and reducing conventional generation by an equal amount. The PV generation output at each system load bus was calculated by multiplying the installed PV capacity at each site by the average fall PV capacity factor for 10:00 A.M. and 11:00 A.M. The distribution of PV output at different areas of the 44-kV and 100-kV systems are shown in Figure 3.10 and Figure 3.11.



**Figure 3.10.** PV Output in the Fall Case at Different Areas in the 44-kV Sub-Transmission

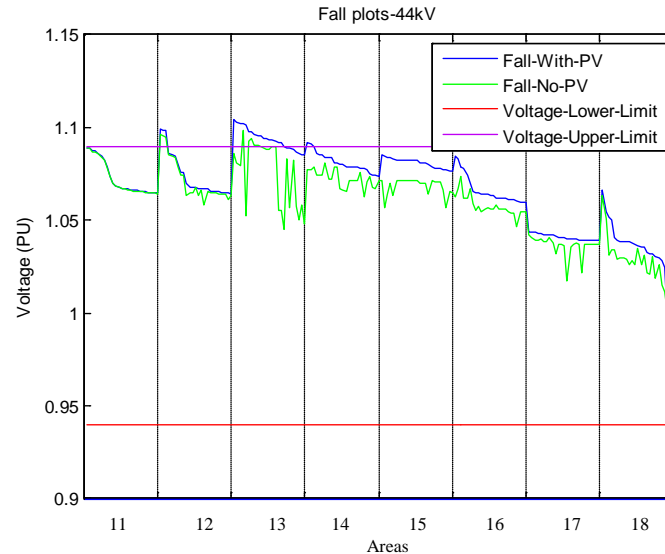


**Figure 3.11.** PV Output in the Fall Case at Different Areas in the 100-kV Sub-Transmission

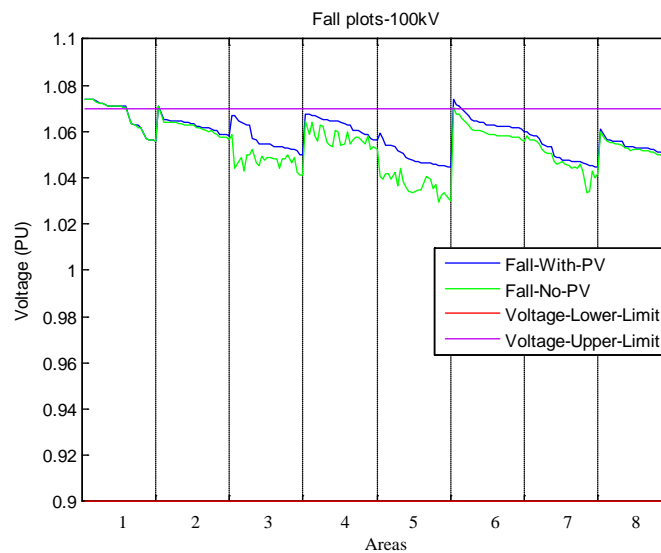
### 3.4.2.2 Fall Case-Voltage Profiles

Highest observed voltage magnitudes in the PV case at different areas of the 44-kV and 100-kV systems are shown in Figure 3.12 and Figure 3.13, respectively.

Study of the fall light load day PV model indicated violation of the 44 kV transmission upper voltage limits (Areas 11, 12 and 13) and 100 kV transmission upper voltage limits (Area 6) as a result of the modeled PV sites connected to distribution stations.

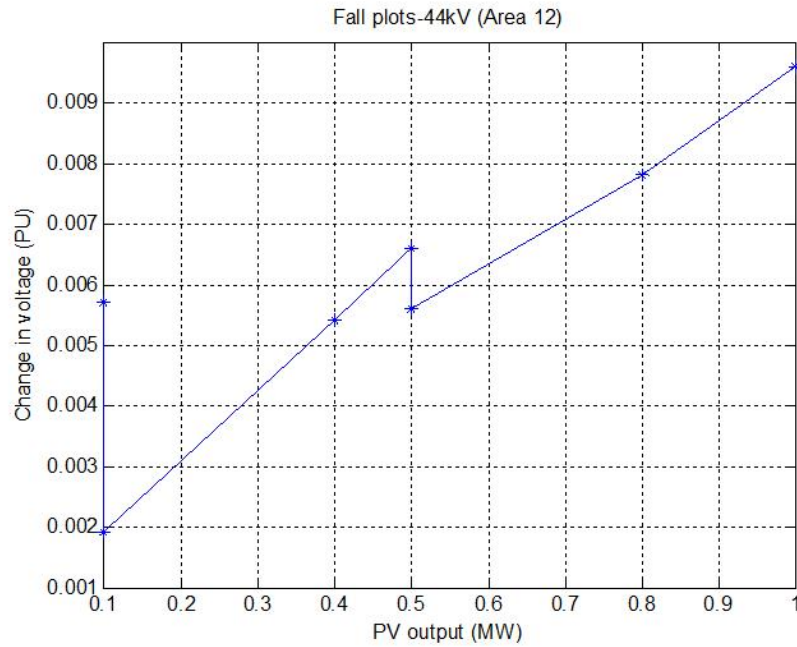


**Figure 3.12.** Highest Voltage Profiles – Fall Case 44-kV Sub-Transmission

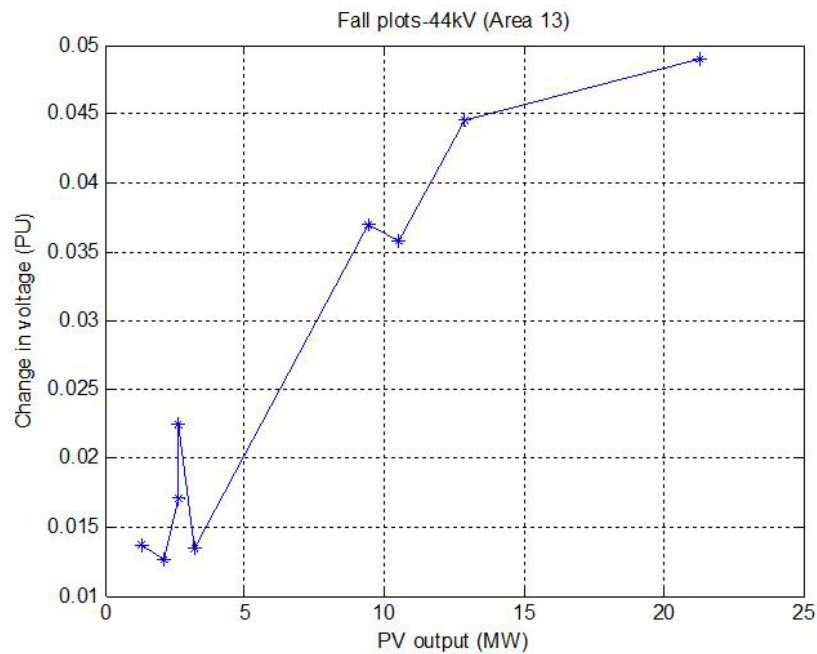


**Figure 3.13.** Highest Voltage Profiles – Fall Case 100-kV Sub-Transmission Case

Relationships between the increase in bus voltages in Areas 12 and 13 of the 44-kV and 100-kV systems versus PV outputs at the corresponding bus in the Fall Case are shown in Figure 3.14 and Figure 3.15, respectively.



**Figure 3.14.** Relationship between the increase in Bus Voltage in Area 12 of the 44-kV System Versus PV Output at the Corresponding Bus in the Fall Case

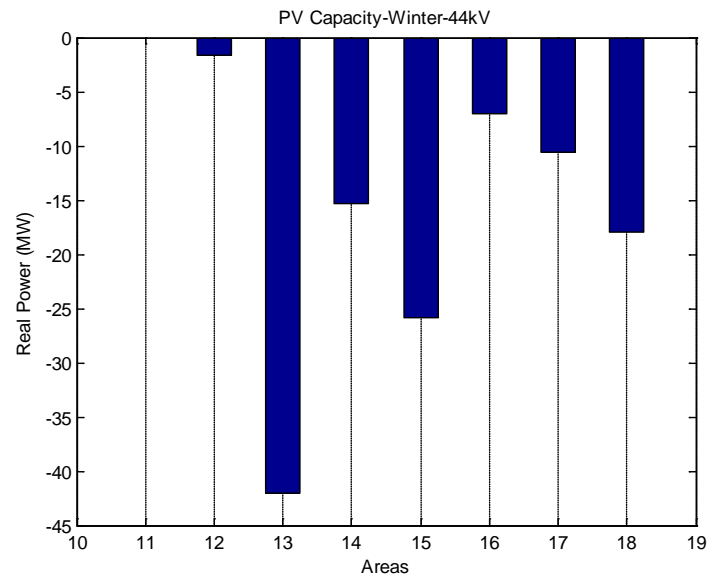


**Figure 3.15.** Relationship between the increase in Bus Voltage in Area 13 of the 44-kV System versus PV Output at the Corresponding Bus in the Fall Case

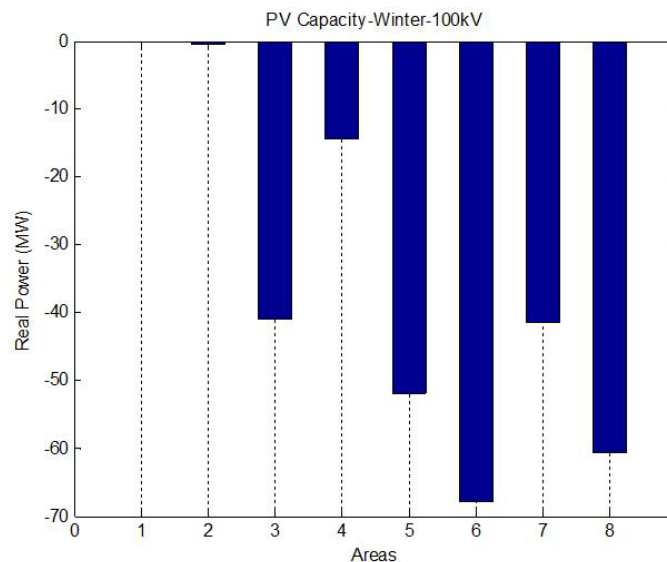
### 3.4.3 Winter Light Hour Load Case

#### 3.4.3.1 2012 Winter Light Load Model Details

The winter light load day model was created using substation loads from January 6, 2012 at 11:00 A.M., with total load of 12,292 MW. The corresponding PV model was created by adding 401 MWs of distributed PV to the winter base case and reducing conventional generation by an equal amount. The PV generation output at each system load bus was calculated by multiplying the installed PV capacity at each site by the average winter PV capacity factor for 10:00 A.M. and 11:00 A.M. The distribution of PV output at different areas of the 44-kV and 100-kV systems are given in Figure 3.16 and Figure 3.17.



**Figure 3.16.** PV Output in the Winter Case at Different Areas in the 44-kV Sub-Transmission

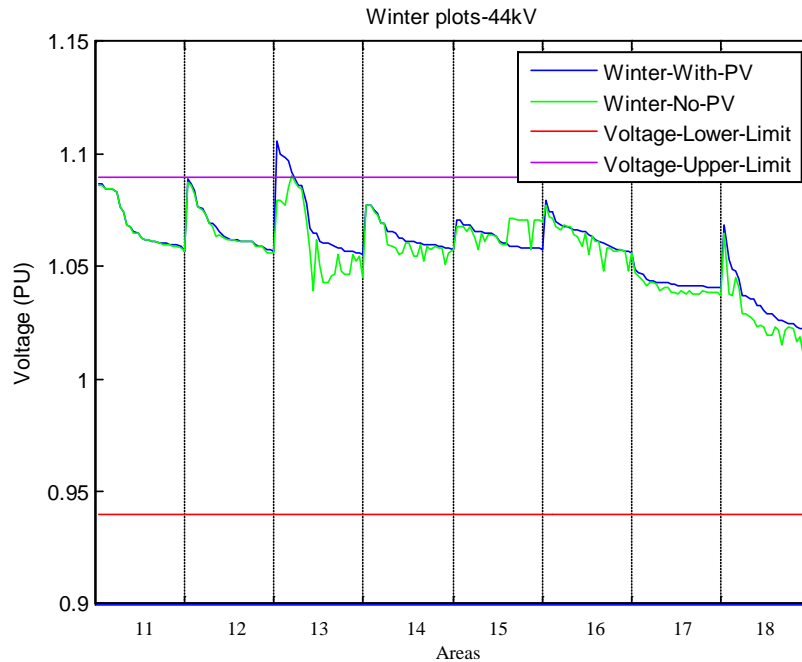


**Figure 3.17.** PV Output in the Winter Case at Different Areas in the 100-kV Sub-Transmission

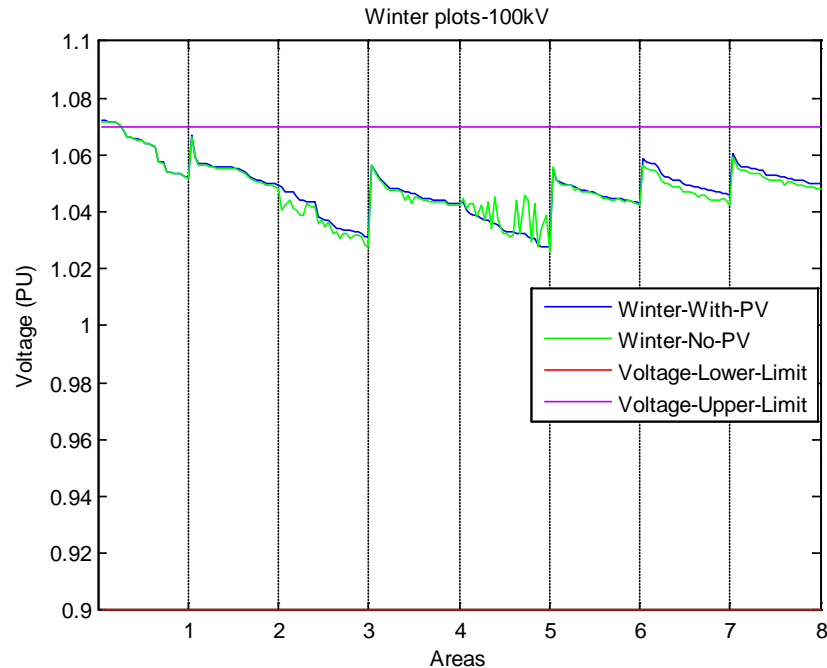
### 3.4.3.2 Winter Case – Voltage Profiles

Highest observed voltage magnitudes in the PV case at different areas of the 44-kV and 100-kV systems are shown in Figure 3.18 and Figure 3.19, respectively.

Study of the winter light load day PV model indicated violation of the 44-kV transmission upper voltage limits (Area 13). There were no violations on the 100-kV transmission system.



**Figure 3.18.** Highest Voltage Profiles – Winter Case 44-kV Sub-Transmission



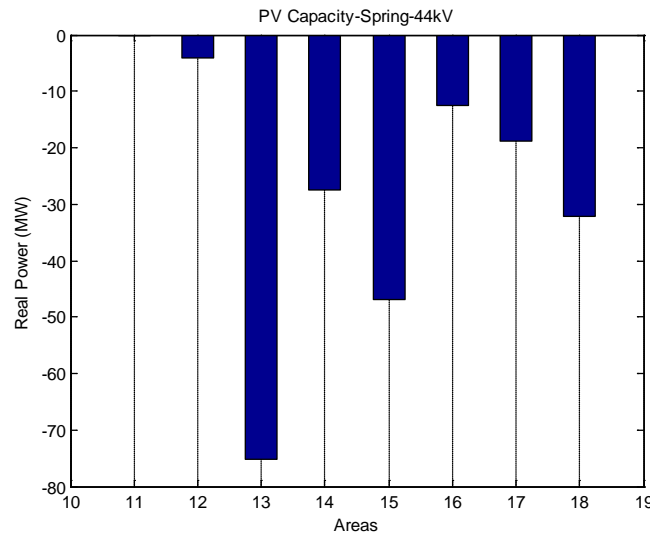
**Figure 3.19.** Highest Voltage Profiles – Winter Case 100kV Sub-Tranmission

### 3.4.4 Spring Light Hour Load Case

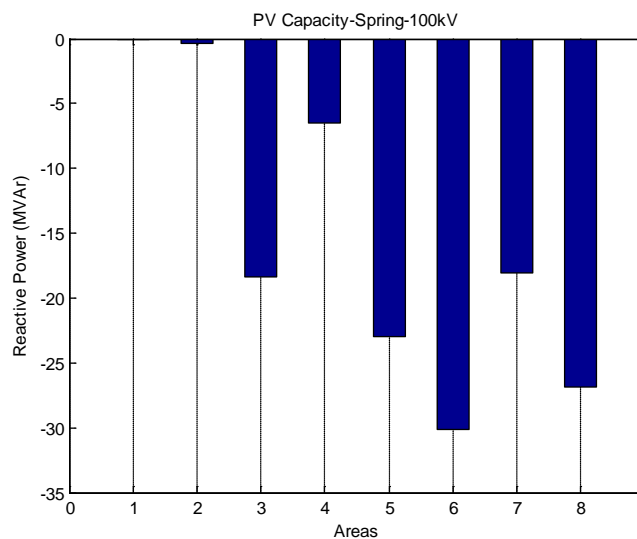
#### 3.4.4.1 2012 Spring Light Load Model Details

The spring light load day model was created using substation loads from April 7, 2012, at 11:00 A.M., with total load of 8,996 MW. The corresponding PV model was created by adding 719 MWs of distributed PV to the spring base case and reducing conventional generation by an equal amount. The PV generation output at each system load bus was calculated by multiplying the installed PV capacity at each site by the average spring PV capacity factor for 10:00 A.M. and 11:00 A.M.

The distribution of PV output at different areas of the 44-kV and 100-kV systems are given in Figure 3.20 and Figure 3.21.



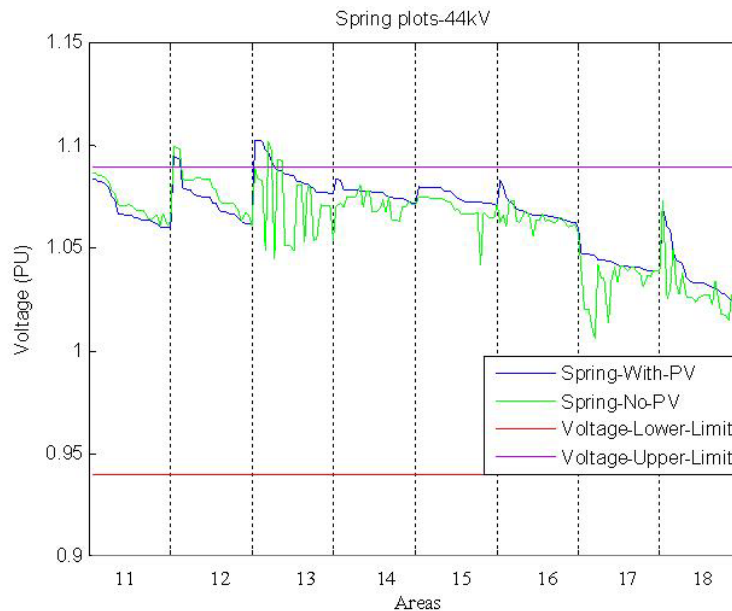
**Figure 3.20.** PV Output in the Spring Case at Different Areas in the 44-Kv Sub-Transmission



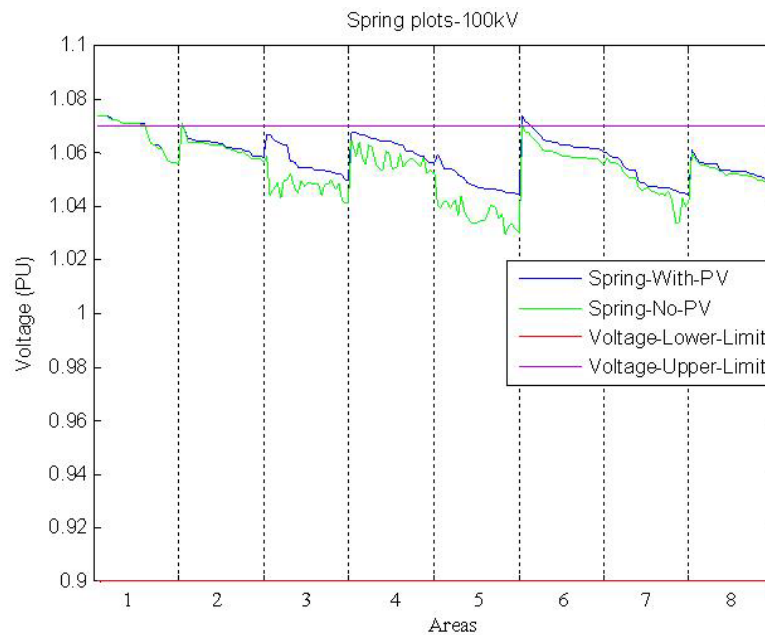
**Figure 3.21.** PV Output in the Spring Case at Different Areas in the 100-kV Sub-Transmission

### 3.4.4.2 Spring Case-Voltage Profiles

Highest observed voltage magnitudes in the PV case at different areas of the 44-kV and 100-kV systems are shown in Figure 3.22 and Figure 3.23, respectively. Study of the spring light load day PV model indicated violation of the 44-kV transmission upper voltage limits (Areas 12 and 13). A few buses in Area 6 of the 100-kV transmission system violated the upper voltage limits in the case with PV.



**Figure 3.22.** Highest Voltage Profiles – Spring Case 44-kV Sub-Tranmission



**Figure 3.23.** Highest Voltage Profiles – Spring Case 100-kV Sub-Tranmission

### 3.4.5 PV Impact on Transmission Losses

The amount of real power losses reduction in the transmission network due to distributed PV depends on many factors such as the type of the conductors in the system, PV outputs and the nature of load. Table 3.1 compares losses for the four cases with and without PV. As expected, the highest reduction occurs in the summer peak load day.

**Table 3.1.** Transmission Real Power Losses Comparison

Case	With PV Losses (MW)	Without PV Losses (MW)	Reduction in Losses (MW)	Reduction in Losses as % of Summer Peak Load
Fall	168.30	180.20	11.9	0.06%
Summer	545.55	583.36	37.81	0.19%
Winter	261.13	271.98	10.85	0.05%
Spring	171.98	190.49	18.51	0.09%

Comparisons for reduction in reactive power consumed in the transmission system are given in Table 3.2. Reactive power compensation in the case with PV is as much as 10 percent in the summer case because the distributed PV is providing reactive power.

**Table 3.2.** Transmission Reactive Power Consumption Comparison

Case	With PV (MVar)	Without PV (MVar)	Reduction in (MVar)
Fall	-429.84	-307.43	122.41
Summer	4,443.45	4,913.24	469.79
Winter	973.02	1043.8	70.78
Spring	-283.91	46.19	330.1

## 3.5 Transmission Study Findings and Discussions

The analysis is based on 1197 MW AC nameplate PV penetration with the assumption that the maximum output of PV will be no more than 65 percent of this value as an average output value based on historical measurements. All PV installations were assumed to operate at 0.97 lagging power factors (i.e., supplying reactive power in the amount of 25 percent of their real power output).

### 3.5.1 Study Findings

The transmission study results identify three key impacts areas: over-voltage violations, transmission real power loss reductions, and lower transmission reactive power consumption. Each impact area is discussed in more detail in this section.

### **3.5.1.1 Over-Voltage Violations**

Voltage magnitude at sub-transmission buses where the distributed PVs are aggregated will have an increase in comparison to the case without PV because the PV systems are assumed to have lagging power factor. The increase in voltage magnitude is proportional to the amount of PV output.

The most affected areas in the Duke Energy system are Areas 12 and 13 in the 44-kV systems where voltage magnitude violated the upper voltage limits in the spring and fall cases. It should be noted these two areas are already near the upper voltage limits in the case without PV. All capacitor banks in these two areas were switched off in both the case with and without PV.

The status of the seven reactors in the Duke Energy system did not change in all cases with and without PV with the exception of the spring case where two reactors were switched on and one reactor was switched off in the case with PV in comparison with the case without PV. That was expected as these reactors are installed in locations far from the substations that have significant PV penetration.

### **3.5.1.2 Real Power Losses Reduction**

The amount of real power loss reduction in the transmission network due to distributed PV depends on many factors such as the type of the conductors in the system, PV outputs and the nature of load. The study found transmission loss reduction benefit is the highest during the summer peak load period. During winter and fall light load conditions, loss reduction will be around one fourth of the loss reduction in the summer case.

### **3.5.1.3 Reactive Power Consumption Reduction**

The study results show that as a result of the PV operating at lagging power factor, there is a reduction in reactive power consumed in the transmission system. Reactive power compensation in the case with PV is as much as 10 percent in the summer. The reduction in transmission reactive power consumption could allow higher real power transfers during heavy loading conditions.

## **3.5.2 Discussions**

### **3.5.2.1 Options for Over-Voltage Mitigations**

The over-voltage violations are clearly linked to the solar PV penetration in each area and to the characteristics of each transmission area. Mitigation procedures should be investigated to overcome voltage control challenges during light load conditions such as:

1. Better coordination between the capacitor banks within the same area and modification of the dead-band logic.
2. Requiring the distributed PV to absorb or provide reactive power based on the system status to maintain sub-transmission within acceptable operational limits.
3. Installing shunt reactors in the substations where over-voltage may become an issue.

### 3.5.2.2 Suggested Future Studies

There are several other studies that are needed to quantify the transmission integration costs and potential savings. These studies need to be performed at different penetrations level such as:

1. Further studies should be done to identify the amount of solar penetration that can be accommodated in each transmission area without violating voltage limits. These additional studies should also include impacts on the higher voltage transmission system to determine penetration limits and constraints on those systems. Since these violations are linked to real project being proposed in these transmission areas, the interconnection studies associated with these projects need to ensure that these voltage violations are properly identified and appropriate mitigation plans developed and presented to the project developers of these projects.
2. Perform a full year production cost simulation (PCM) using a nodal model to
  - Calculate the total real power losses reduction in MWh per year, and
  - Utilization factors of major transmission paths.
3. Short circuit contribution of PV and the impact on protection coordination.
4. Transient stability (impact of distribution system disturbances on transmission networks)
  - Islanding of distributed PV during feeder fault conditions (IEEE 1547), and
  - Significant changes in distribution system net-load, such as morning and afternoon ramps and partially cloudy days.
5. Import snapshots from PCM, and run chronological AC power flows to determine the potential of voltage stability problems.
6. Degradation in inertia and frequency response.

## 4.0 Distribution Study

### 4.1 Scope

The distribution study was performed in two parts, a system-wide impact study at 30-minute time steps across all feeders within Duke Energy's DEC service territory that currently have solar DG in the interconnection queue, and a detailed 3-minute time step simulation of a single feeder which has a 5000 kW solar system currently installed. The study was DEC focused because tools used to evaluate the impact of solar DG—Alstom Distribution Management System (DMS) and Distribution Operator Training Simulator (DOTS)—are only deployed in DEC. The goal of the first study was to determine the system-wide impacts on technical losses, over- and under-voltages, overloads, and, in a very general manner, on regulator tap operations. As tap operations occur at a much greater frequency than 30 minutes, a separate three-minute time step study was commissioned to study the impact of intermittent generation on regulator tap operations on a single feeder.

The first study was designed to utilize models of every feeder in the Duke Energy portfolio. All of the models currently reside, and are continuously validated and updated on a nightly basis, within the Alstom DMS and DOTS. The system is capable of performing power flow, fault calculations, and simulations over a limited period. The goal was to capture the general trend of system-wide effects on losses, overloads, voltage, and regulator tap changes, without spending significant resources to perform highly detailed simulations of each feeder. From these studies, it is shown that there is a wide variation of impacts. These impacts can be affected by system topology, equipment, penetration level, and seasonal variation. With system losses, both real and reactive, there is a definite dependence on the season evaluated. During summer months, and to a lesser degree winter months, a majority of feeders show decreased losses. During spring and fall months, losses remain relatively level. However, there is significant variability between individual feeders. Voltage is impacted by an increase in over-voltage violations during spring and fall months, but a decrease in under-voltages during summer and winter months. Overloads generally decreased, especially during summer months. It should be noted that most violations would generally be addressed during an interconnection study.

The second study was designed to use one specific feeder that currently has a 5-MW PV system connected to it. The goal was to study the change in behavior during a “worst case” 4-hour period (low loading and high solar output and variability, with reverse power flow on the system). This feeder was selected because of it has similar characteristics to other circuits within the DEC service territory where large amounts of PV has been or is being connected (rural with wide geographic dispersal of load ). The model used the same tool as the system-wide study; however, the focus and goal of the second study was to specifically capture regulator tap changes and voltage impacts at a more granular level by using a 3-minute time step. Because of time and cost constraints, the study was limited to one feeder. During the 4 hours studied, regulator tap operations increased but voltage was controlled within standards, real and reactive line losses increased, and an overload occurred near the generation interconnection. It should again be noted that this represents the “worst-case” scenario.

The following sections describe the impact studies in greater detail, drawing general conclusions from the results of the simulations. This study represents a first effort at quantifying some of the benefits and impacts of installing solar DG on the DEC service territory. It should not be considered comprehensive. A number of benefits and impacts are not analyzed in this work and left for later research.

## **4.2 Methodology**

### **4.2.1 System-Wide Impact Study**

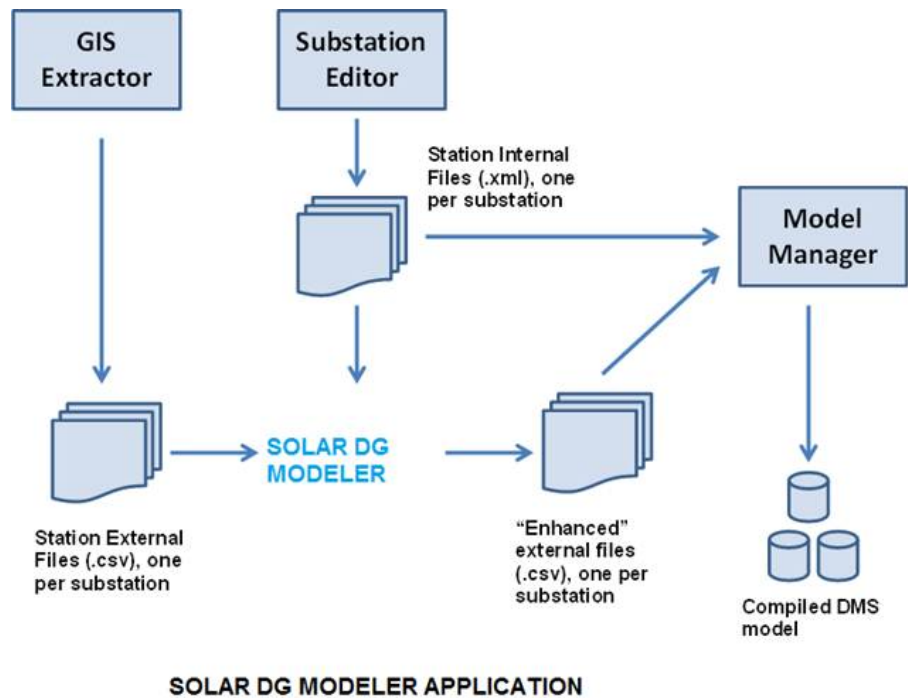
#### **4.2.1.1 Location of Projected PV Systems**

This distribution study analyzes the impacts of 1197 MW of solar on the distribution grid as allocated in Section 3.3. For the purposes of this study, 461 out of 2545 feeders and 262 out of 661 substations had DG added to the circuit, varying between 2 kW and 30,000 kW of solar DG installed. The circuits selected for the study are the circuits that either already have solar connected to them or have requested for solar to be connected in the interconnection queue. Appendix C shows how the PV systems were distributed to each circuit.

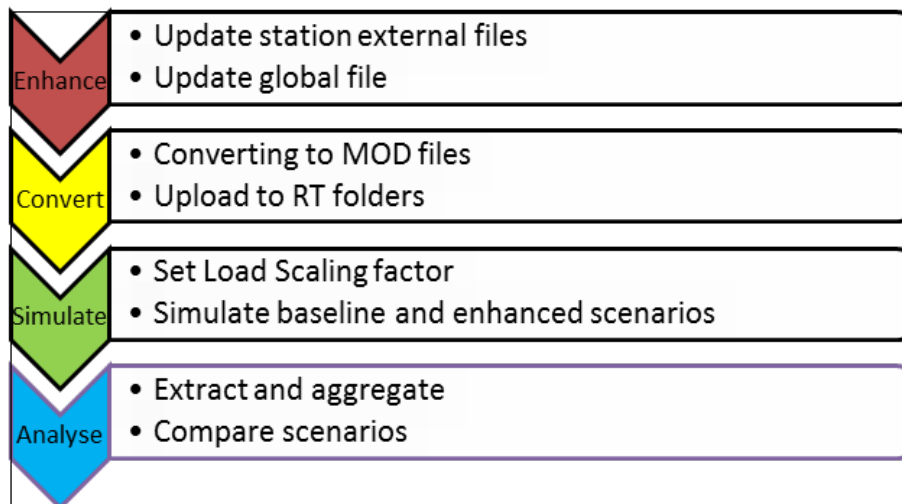
For the purpose of this study, solar sites were distributed along the backbone, or main three-phase trunk, section of all circuits and not along tap lines. To distribute the solar sites along the backbone, Alstom created a distributed solar generation placement algorithm. This algorithm took the backbone distance and number of solar sites to distribute on the circuit to allocate the sites on the circuit. For example, if the backbone of the circuit was 1000 feet long and the circuit needed to have one 5-MW solar system installed, the algorithm would place the solar generator 500 feet down the backbone. If the backbone was 2000 feet long and the circuit was to have three solar generators attached then the algorithm would place the generators every 666.66 feet. While this is a simplification, and may not wholly represent the placement of the final installations, it provides a starting point to evaluate the potential benefits and impacts. During an interconnection study of an individual installation, more detailed (and less broad) values can be determined.

#### **4.2.1.2 Simulation Tool and Setup for System-Wide Study**

The Solar DG Modeler (an Alstom DOTS component) is an offline-modeling tool that is designed to support DG penetration studies. It reads in customer-supplied DG installation and output profile data, adds generators to the distribution network station models, and allows the user to control the workflow for bulk model updates, conversion, and initiation of operational impact studies. The DOTS environment is used to analyze network operation over the course of time, with and without DG. The power flow analysis is run every 30 minutes, taking into account load profiles, DG output schedules, and local control device actions. This process is illustrated in Figure 4.1. After the study period is over, power flow results are extracted and aggregated for analysis as illustrated in Figure 4.2.



**Figure 4.1.** Description of Workflow for Solar DG Modeler

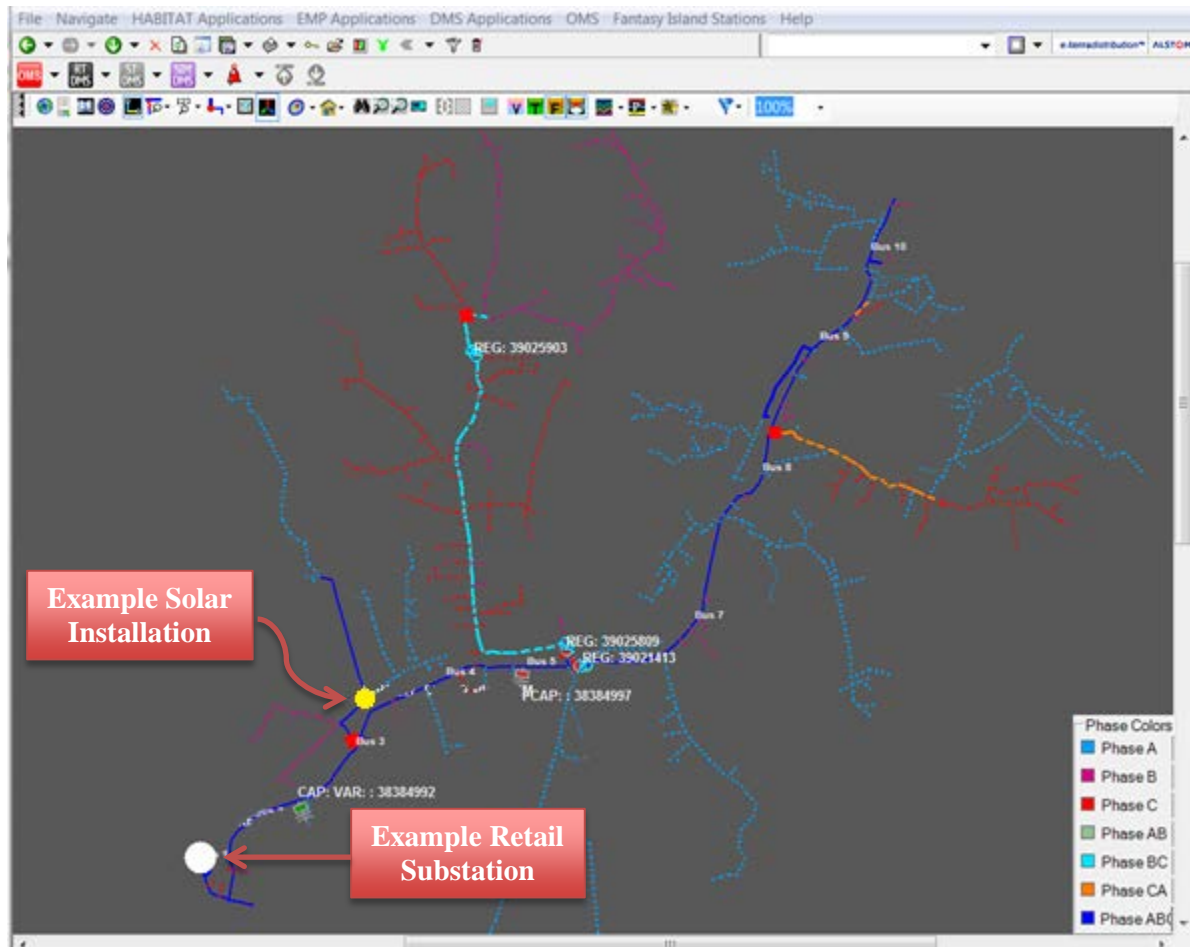


**Figure 4.2.** Workflow for Converting DMS Models for Simulation Analysis

### 4.2.2 Intermittency Study

An example retail substation in Duke Energy's service territory was selected for a solar generation intermittency study. This is an actual substation and retail solar installation, but the name has been removed. The substation has a single 5-MW solar system connected and is representative of other solar sites currently in the queue. The solar site is located in a rural area that is common for most 5-MW sites today due to land cost and availability. The example solar site is located approximately 2 miles from the substation. The existing back bone of the example feeder is approximately 4 miles long. A 44-kV

transmission line serves the substation before stepping down to 12 kV for distribution. A 5-MW solar PV installation is located on the upstream portion of circuit and provides enough power to regularly reverse feeder-head flow. Figure 4.3 shows the DMS geographic display of the example Ret L1203, where dotted lines represent underground line segments and phase coloring follows the key shown in the bottom left-hand corner of the viewport. Labels have been added to all capacitor, regulator, and voltage monitoring bus locations for clarity.



**Figure 4.3.** Geographic Display of Example Retail Substation and Example Solar Site

Most distribution studies rely on planning models that may be using out-of-date information or settings. By using the operational model, which is updated on a nightly basis, models that are more accurate can be used to evaluate the effects of the solar installation. After review with Duke Energy engineers, the following changes were made to the model source data to improve the accuracy of the model:

1. All field regulators changed from Remote Only to Local Only control (SCCONTROLLABLE\_TF changed from 2 to 1).
2. All field regulator PT ratios were changed from 63.5 to 60 so that internal LDC circuit uses a  $7200/60 = 120\text{V}$  base control voltage.
3. Field regulator 39025809\_B's CT ratio was changed from 150 to 750 to match the C phase regulator.

4. L1203 station regulator updated as follows:
  - Secondary winding regulation defined as reversible
  - Updated secondary winding forward and reverse regulation nodes
  - LDC circuit CT ratio changed from 750 to 1500 per device database
  - LDC R value changed from 6 to 7 per device database
5. A single, 5-MW generation unit was placed on the feeder and an associated generator model was created.

In future work, this study may indicate that model cleansing may need to be performed prior to interconnection studies to more accurately reflect current operations, particularly in the context of voltage control devices and set points. It may indicate an overall need to address current model data in a systematic manner. These changes to regulator set points were not required in the system-wide impact study, as the 30-minute time step was much longer than typical regulator control actions but did not affect the regulated voltage level.

### **Simulation Methodology**

Historical feeder-head supervisory control and data acquisition (SCADA) data are used to define feeder-head flow which is then allocated downstream to each portion of the circuit according to load point, load profiles and electrical parameters. An unbalanced power flow is solved and resulting data is captured for this base case scenario where no solar generation is present. Next, the PV generator is connected to the network and power flow is solved again at the same evaluation time and loading. This process is repeated for each 3-minute time interval for the entire study period, in this case, a single spring day during a 4-hour period. Generator output follows a schedule defined by the SCADA data for April 12, 2013, and locally controlled regulators and capacitor banks operate according to their modeled settings.

### **Assumptions**

The following assumptions were made in this study:

- A balanced substation high-side voltage of 1.05 pu (46.2 kV LL) throughout the simulation
- Regulator and capacitor local controller time delay is not taken into consideration
- Regulator reverse regulation settings are equivalent to forward regulation settings
- Regulators start from a nominal tap position on each initial power flow iteration
- Load and solar output is averaged in 3-minute increments; intermittency that is more granular is not considered
- Feeder-head power factor used in defining loading is assumed to be equal across phases.

Note that the assumptions used for regulator and capacitor controls may lead to less accurate results, particularly considering the 3-minute time steps used in the simulation. This will be discussed in further detail in the results section.

## 4.3 Data Inputs

### 4.3.1 System-Wide Impact Study

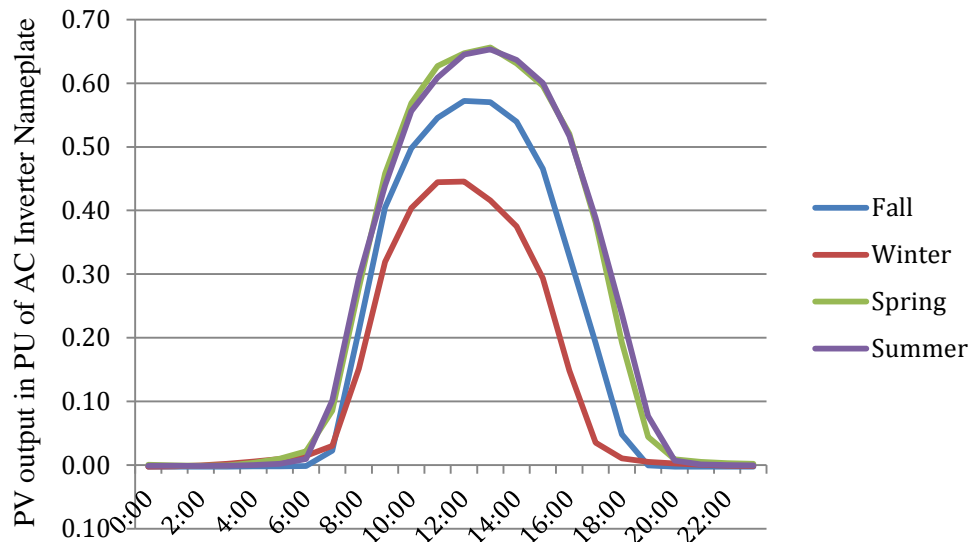
#### 4.3.1.1 Solar Profiles

To create the seasonal production and power factor curves, the data for the seven sites previously noted in Section 3.3 were used. Analysis was separated into four seasons as shown in Table 4.1.

**Table 4.1.** Data Ranges used for Creating Production Curves

Season	Data Used
Spring	March 2013 – May 2013
Summer	June 1-17, 2013; June 18-30, 2012; July 2012 – August 2012
Fall	September 2012 – November 2012
Winter	December 2012; January 2013 – February 2013

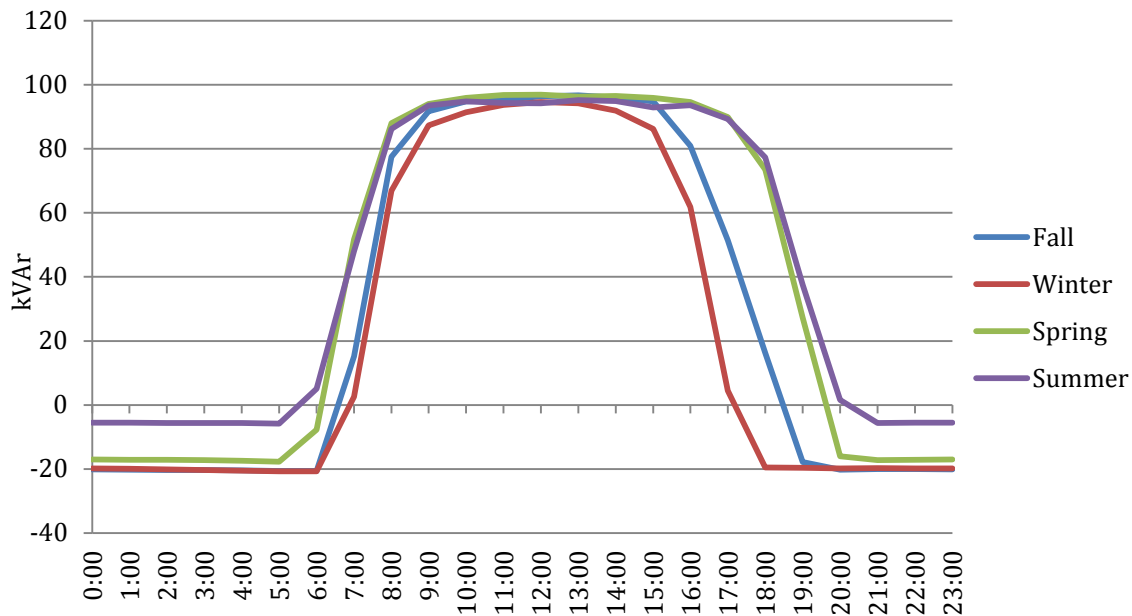
The daily 3-minute data from each of the seven sites were averaged to create a production curve to represent the average solar output across the area of study, as described in Section 3.3. For application to the system-wide impact study, the 3-minute values were then averaged across the 30-minute simulation interval to create 30-minute daily production curves as shown in Figure 4.4. Notice that this represents an average of measurements across time and solar installations; hence, the capacity factor peaks at less than 70 percent and significantly reduces the variability of the solar input. This has potential impacts on some of the studies, as it does not accurately reflect a traditional peak study, nor is the variability of the generation resource captured. Future work should attempt to address the issue of large-scale data management for time-series analysis.



**Figure 4.4.** Average Production of Seven Monitored Solar Sites at 30-Minute Intervals

The power factor profile was also created using the 3-minute data from the sites, as shown in Figure 4.5. It is important to note however, to maximize their production, several developers are

installing additional panels above the rated inverter capacity, as well as dynamically changing the power factor (within current interconnection requirements), to maximize the amount of energy production.



**Figure 4.5.** Average Reactive Power of Nine Monitored Solar Sites

#### 4.3.1.2 Load Profiles

To run the distribution study the load profile of each circuit had to be created. With the study being performed in 2013 and only partial data available for 2013, the decision was made to use 2012 load data as the study case. Winter and summer load cases used 2012 peak days, while spring and fall cases looked at the lowest load days from 2012.

So that the distribution and transmission studies aligned, the distribution study used load factors for each season and applied it proportionally to the scale modeled loading to match the telemetered system load shown in Table 4.2. The load was allocated throughout the feeder at each load connection point using load profiles designed for different classes of customers. The load was spread throughout the system in an unbalanced manner, but at the substation, the peak load resulted in the values shown in Table 4.2.

**Table 4.2.** Telemetered System Load Data Used to Create Distribution Load Shapes

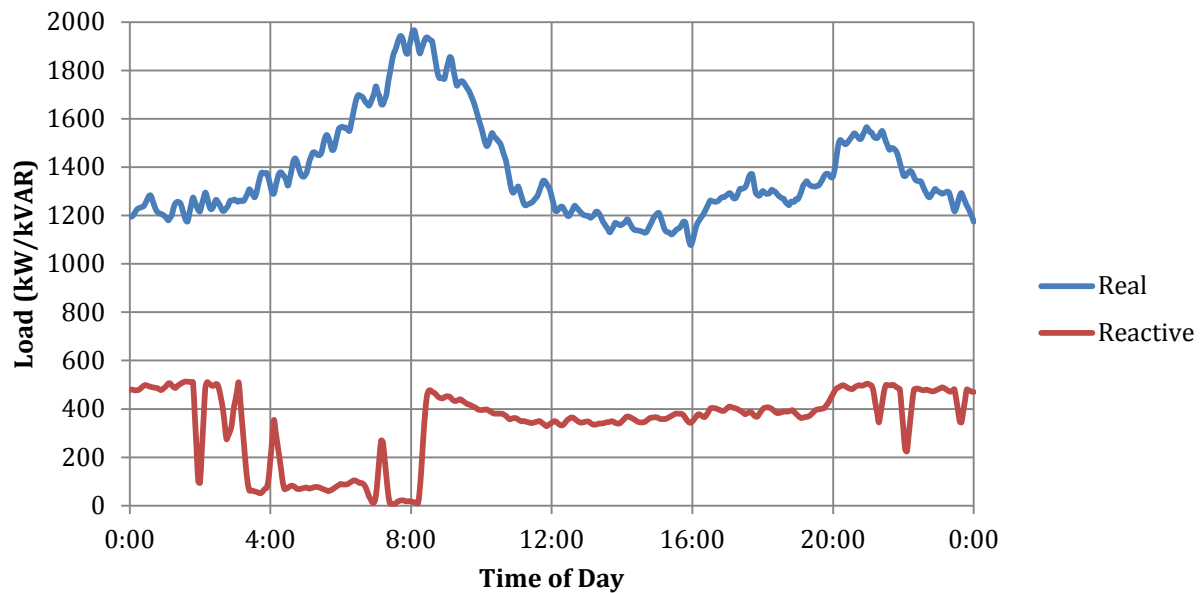
Date	Real Power (MW)	Reactive Power (MVar)	Power Factor (lagging)
January 6, 2012, 11 A.M.	8,103	1,157	99.3%
April 7, 2012, 11 A.M.	5,791	428	99.7%
July 26, 2012, 5 P.M.	13,461	2,437	98.4%
October 21, 2012, 11 A.M.	5,852	374	99.8%

The existing peak load on the circuits ranged from 0.158 MW to 46.5 MW. When comparing the peak load to the solar system installed on the circuits the percentages ranged from 0.01 to 323 percent.

This number was calculated by comparing the total solar kW allocated to the circuit to the peak kW load of the circuit.

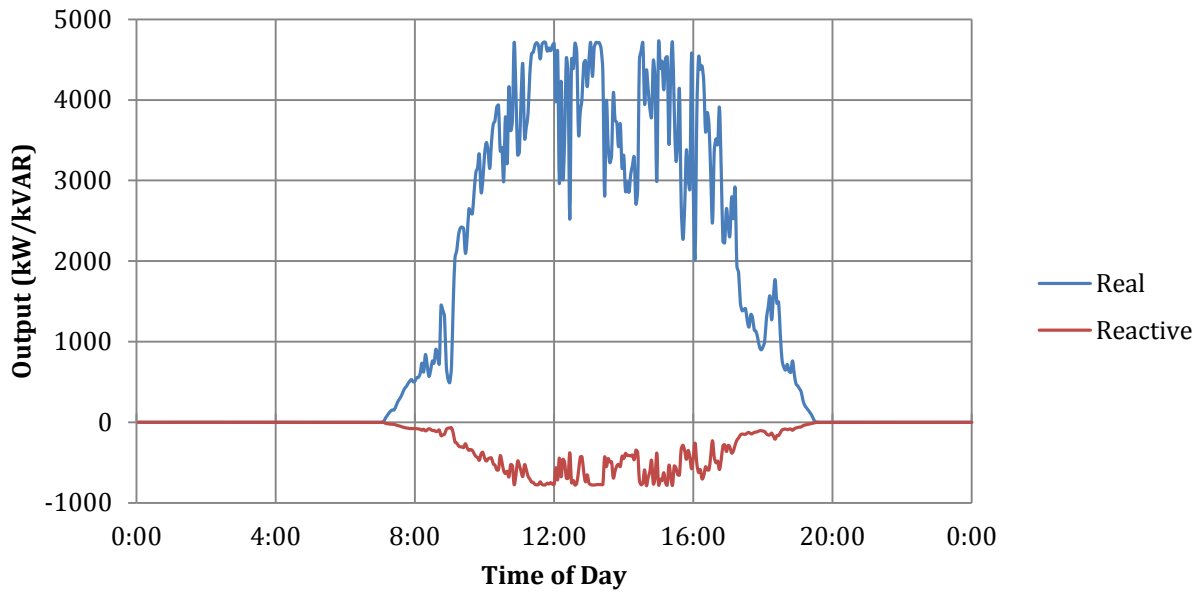
### 4.3.2 Intermittency Study

To create a base case, measurements prior to the installation of the 5-MW solar station had to be used, as the addition of solar DG hides the overall load. To be self-consistent with the other studies presented in this document in terms of the year of study, feeder breaker SCADA data in 3-minute increments for April 7, 2012, was used. During this period, the PV farm had not been installed and was not online so is used to determine a baseline loading. Figure 4.6 shows the feeder three-phase real and reactive load without solar DG.

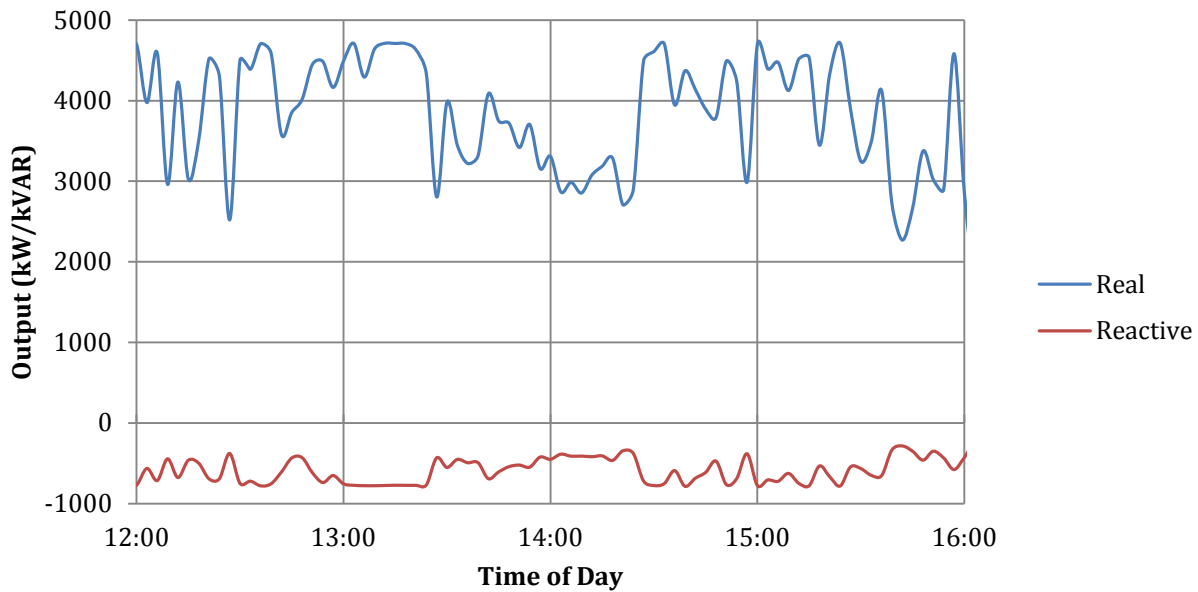


**Figure 4.6.** Daily Load on Feeder Breaker for Example Feeder (April 7, 2012)

Figure 4.7 shows the real and reactive output of the PV farm on April 12, 2013. Solar generator output data were provided in 3-minute increments as telemetered by an interconnection re-closer. This date was chosen for the solar case as it represents a high-variability day that also had similar weather characteristics to the load data used (April 7, 2012). No major feeder changes, beyond those driven by the addition of solar DG, were logged between those dates. Figure 4.8 shows the same data from noon to 4:00 P.M.



**Figure 4.7.** Output of PV Farm for April 12, 2013



**Figure 4.8.** Output of PV Farm from Noon to 4:00 P.M. on April 12, 2013

The production model was extracted from the production-modeling server in December 2013, representing the most up-to-date equipment settings. Again, no major differences in feeder topology were logged between these dates. Tables 4.3 and 4.4 show how locally controlled capacitors and regulators on sample circuit are modeled. A few corrections on regulator settings, highlighted in yellow in Table 4.4, were made after discussion with Duke Energy Grid Management engineers.

**Table 4.3.** Capacitors and Settings on the Example Feeder

ID	Control	Connected Phases	Sensing Phase	Size (kVAR)	On Setting (kVAR)	Off Setting (kVAR)
38384992	VAR	ABC	A	450	540	4.95
38384997	Fixed	ABC		450	720	6.6

**Table 4.4.** Regulators and Settings in L1203

ID	Phase	Sensing Phase	Model	Rated Primary & Secondary Voltage (kV)	Nominal Primary & Secondary Voltage (kV)	Voltage Target (V)	Bandwidth (V)	LDC - R (Volts)	LDC - X (Volts)	CT Ratio	CT Secondary rated amps	PT Ratio
L1203	ABC	A	REG_500_13.2_RET_10_YYR3	7.62	7.2	121	3	7	0	1500	0.2	60
39025809_B	B	B	TCR_10R_10L_0.625_30	7.62	7.2	123	3	3	0	750	0.2	60
39025809_C	C	C	TCR_10R_10L_0.625_30	7.62	7.2	123	3	3	0	750	0.2	60
39021413_A	A	A	TCR_7.5R_7.5L_0.625_30	7.62	7.2	123	3	4	0	1250	0.2	60
39021413_B	B	B	TCR_7.5R_7.5L_0.625_30	7.62	7.2	123	3	4	0	1250	0.2	60
39021413_C	C	C	TCR_7.5R_7.5L_0.625_30	7.62	7.2	123	3	4	0	1250	0.2	60
39025903_B	B	B	TCR_10R_10L_0.625_30	7.62	7.2	124	3	0	0	500	0.2	60
39025903_C	C	C	TCR_10R_10L_0.625_30	7.62	7.2	124	3	0	0	500	0.2	60

While this study is not all-inclusive, and only covers the impact to a single feeder, it is designed to be somewhat representative of a relatively common installation type: a large solar plant on a rural distribution feeder. The results from this study should not be widely applied, but rather provide some indication of the impacts during a “worst case” scenario of high solar output and low loading. The results may be used to indicate when it is appropriate to perform more detailed interconnection studies.

## 4.4 Results

This section will present the results of the previously described simulations. The system-wide impact of losses, over- and under-voltages, and overloads will be presented first. This will focus on general trends in the change of operations when adding solar DG, and not specific feeder results. These will be followed by the results of the intermittency study on a single feeder, and the observed impacts on power factor, real and reactive line losses, and regulator tap operations. These results should not be widely generalized, but provide an indication of some of the impacts at a higher granularity level.

### 4.4.1 System-Wide Impact Study

#### 4.4.1.1 Losses

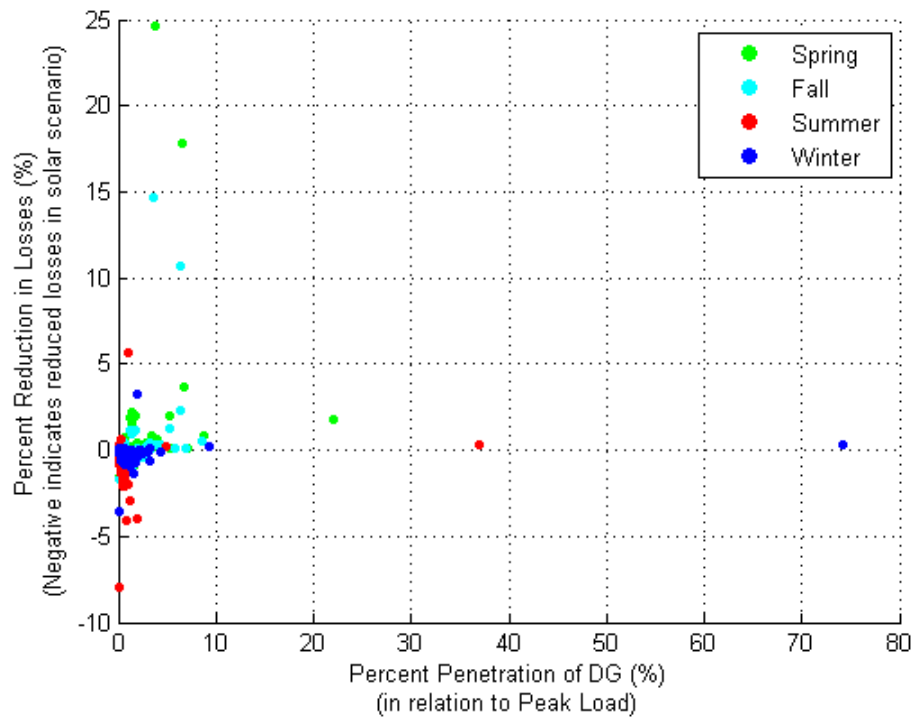
On the bulk of system feeders, the real power losses decreased with the addition of PV. However, the differences varied widely among different feeders and different seasons. Table 4.5 shows the mean and

standard deviation of the change in real power losses as a percentage of the total energy consumed for all of the feeders that were tested when adding DG to the system. In addition, the sum of the total change in energy losses is shown. Note, that a negative number indicates a reduction in losses when adding solar DG to the feeder. As an example, a 10 MVA peak load feeder consumes (for example) 100 MWhs per day. If the losses were 4 percent or 4 MWh, then a change in losses of -0.38 percent would equate to a total of 3.62 percent losses, or 3.62 MWh, and a savings of 0.38 MWh.

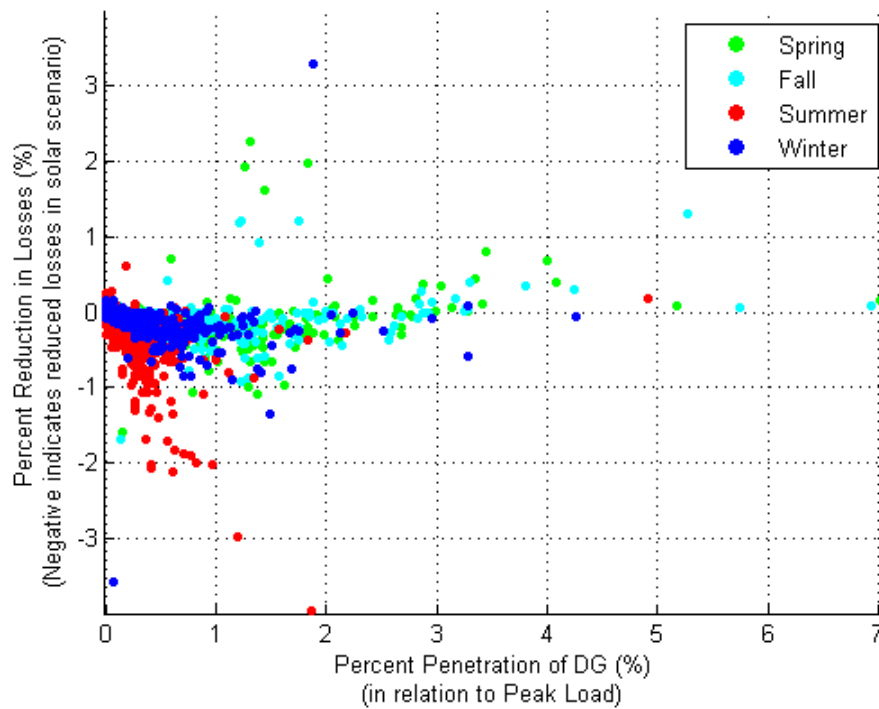
**Table 4.5.** Change in Real Power Losses by Season (negative indicates reduced losses)

	Mean (%)	Standard Deviation (%)	Annual Losses (MWh)
Summer	-0.269 %	0.755 %	-32,641
Winter	-0.110 %	0.330 %	-8,517
Spring	0.027 %	1.464 %	672
Fall	-0.005 %	0.931 %	-484
Total			-40,970

On average, feeders show a reduction in losses due to the addition of solar DG, particularly in the summer season. Spring and fall indicate negligible changes in losses, on average. The average reduction in losses per feeder with installed DG is approximately 89 MWh on an annual basis. However, there is a wide range in the individual feeder results. Figure 4.9 and Figure 4.10 show the change in circuit losses versus the penetration of solar DG installation in relation to the peak load (e.g., 5 MW of installed solar capacity on a feeder with a 10 MW peak equates to 50 percent penetration). The graphics highlight the wide variation in the change in losses and the results are highly dependent on the type of circuit, the size of the DG installation in relationship to the feeder, placement of the DG, and the amount of load on the circuit. While the average feeder experienced an 89-MWh reduction in losses (annually), the individual feeders ranged from a 5124-MWh reduction to a 6757-MWh increase in losses. There is a large cluster of feeders showing a change in losses between 0.5 and -1.5 percent, with a few noticeable outliers. The high-loss feeders may indicate a need for capital investment on that particular feeder.



**Figure 4.9.** Real Power Loss Reduction versus Percent DG Penetration

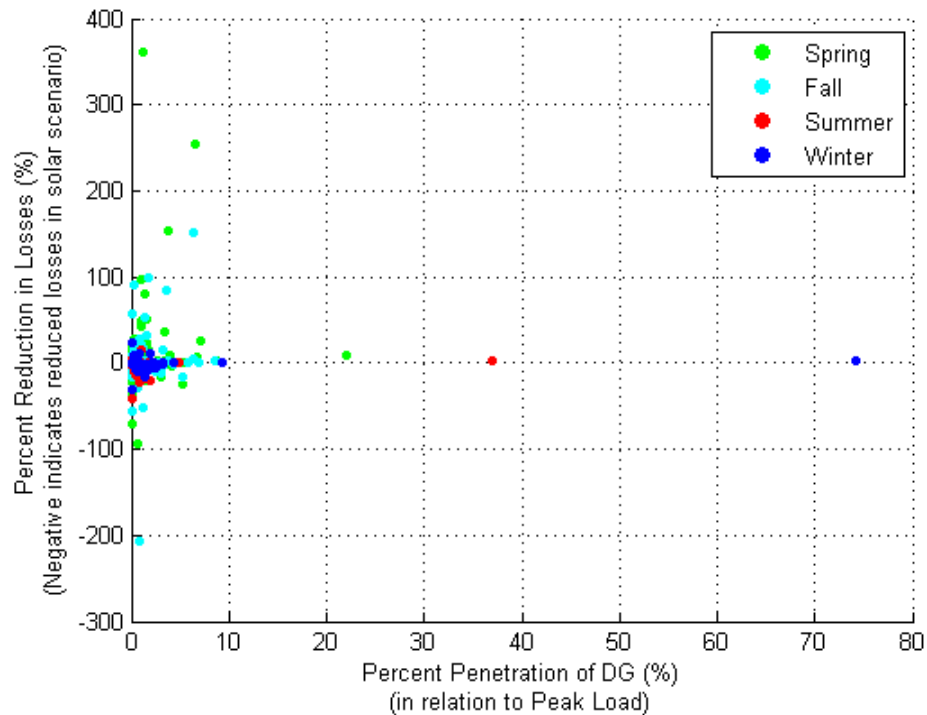


**Figure 4.10.** Real Power Loss Reduction versus Percent DG penetration (zoomed)

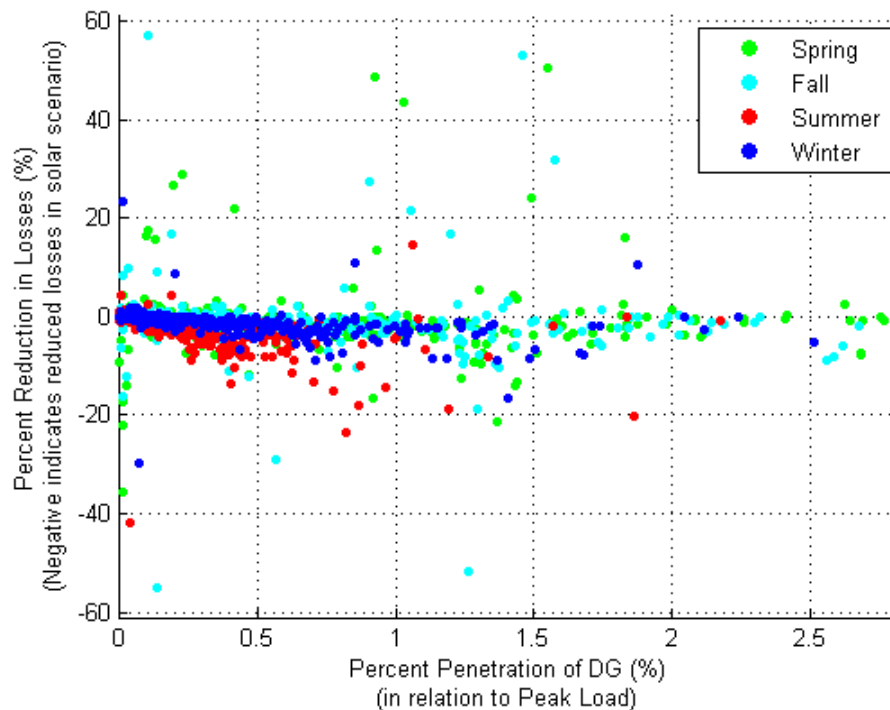
Reactive power loss results show similar trends to real power loss results, but with a much greater standard deviation between the different feeders. Table 4.6 shows the change in reactive losses, while Figure 4.11 and Figure 4.12 plot the losses as a function of the penetration of DG installation. Again, the general trend is a reduction in reactive power losses with a few significant outliers, but is highly dependent on the given feeder topology and penetration level. The reduction of reactive losses can be attributed to the solar installations producing reactive power and reducing overall reactive power flows.

**Table 4.6.** Change in Reactive Power Losses by Season (negative indicates reduced losses)

	Mean (%)	Standard Deviation (%)	Annual Losses (MVA <sub>r</sub> -h)
Summer	-1.366 %	2.976 %	-65,479
Winter	-0.714 %	2.136 %	-17,354
Spring	-0.688 %	17.613 %	-3,297
Fall	-0.062 %	12.205 %	-3,896
Total	-	-	-90,026



**Figure 4.11.** Reactive Power Loss Reduction versus Percent DG Penetration



**Figure 4.12.** Reactive power loss reduction versus percent DG penetration (zoomed)

Losses are an important component to understand when evaluating DG. Because DG is typically thought of as reducing load at the location, most tend to automatically assume that DG will always improve line losses therefore provide a financial benefit by reducing the energy needs. However, what this study found is line losses are not always improved. There are many factors such as native load on the circuit, line configuration including wire size and distance, and DG size and location that impact if the DG provides line loss reduction or line loss increases. Losses are built into the customer rate therefore it is important to understand how each specific DG will impact a given feeder.

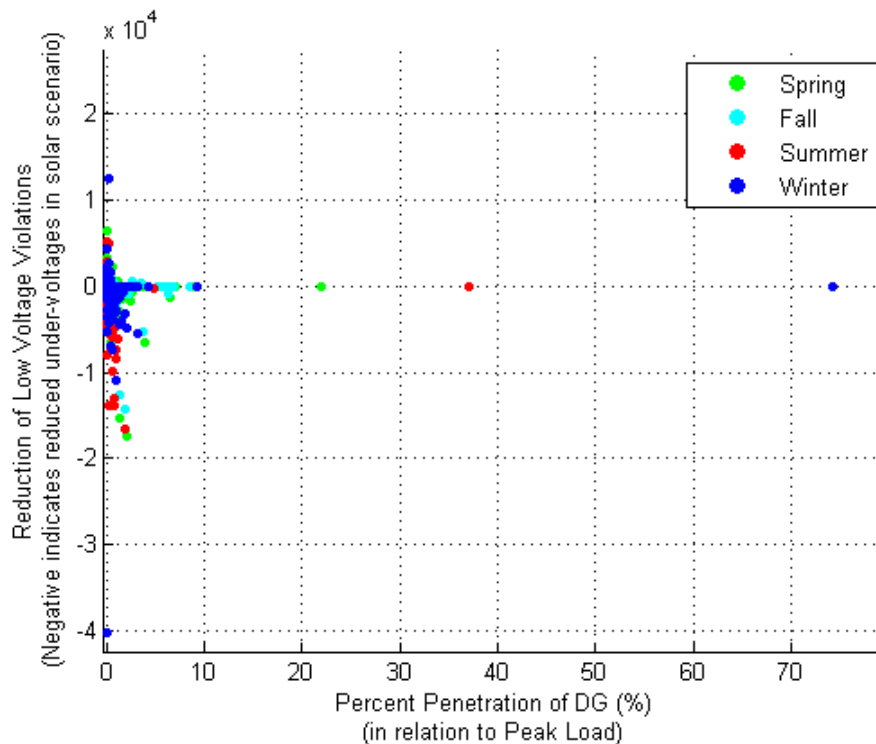
#### 4.4.1.2 Over- and Under-Voltage

Voltages are required to be maintained within voltage standards set by ANSI standard C84.1, in general, between 114 and 126 V. Excessive voltage violations can cause premature equipment wear and can increase customer complaints. Addition of solar DG tends to raise voltage levels as load is offset by the injection of power at the distribution level. Excessive DG power output, especially during low load demand periods, can drive voltages much higher, requiring engineers to evaluate the changes and crews to change tap settings or voltage regulator settings as higher and higher penetration of solar on feeders occurs. Also, the resulting voltage fluctuations of solar may cause increased tap changing operations, which may reduce the life of tap changing transformers at substations, line regulators, or voltage control capacitors, requiring increased maintenance or replacement.

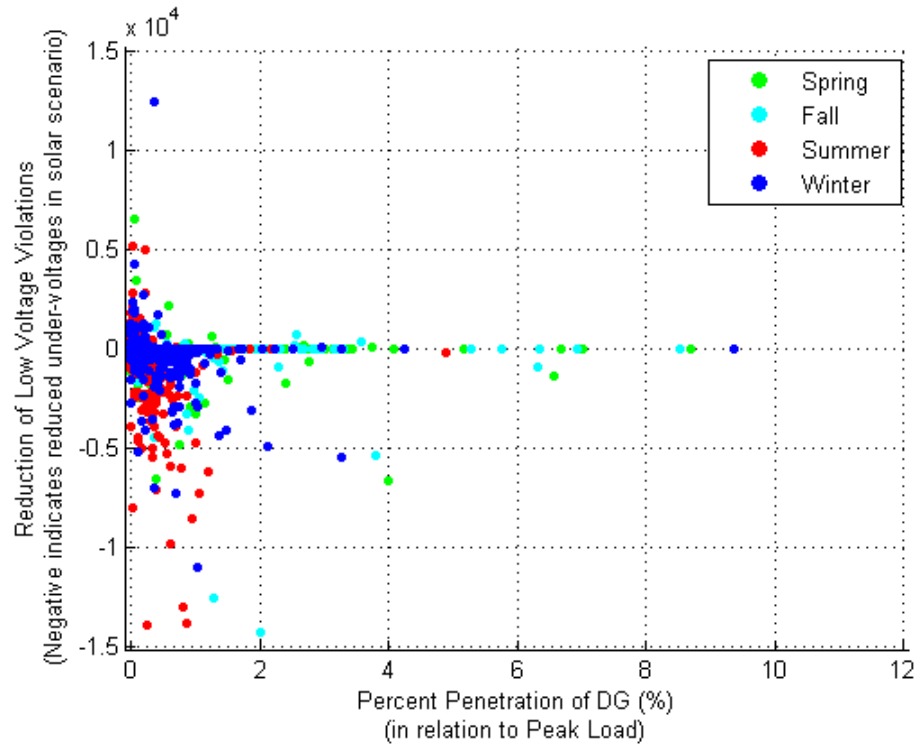
The studies performed by the Alstom DOTS measured high and low voltage violations in terms of number of nodes with a violation times the number of time steps the violations occurred. In other words, 10,000 violations may indicate 100 nodes with a violation for 100 hours or 10 nodes with violations for

1000 hours. The lack of visibility into that measurement reduces its overall applicability, but evaluation of the overall change in voltage violations between base operation and operation with solar DG is indicative of the overall change in voltage behavior.

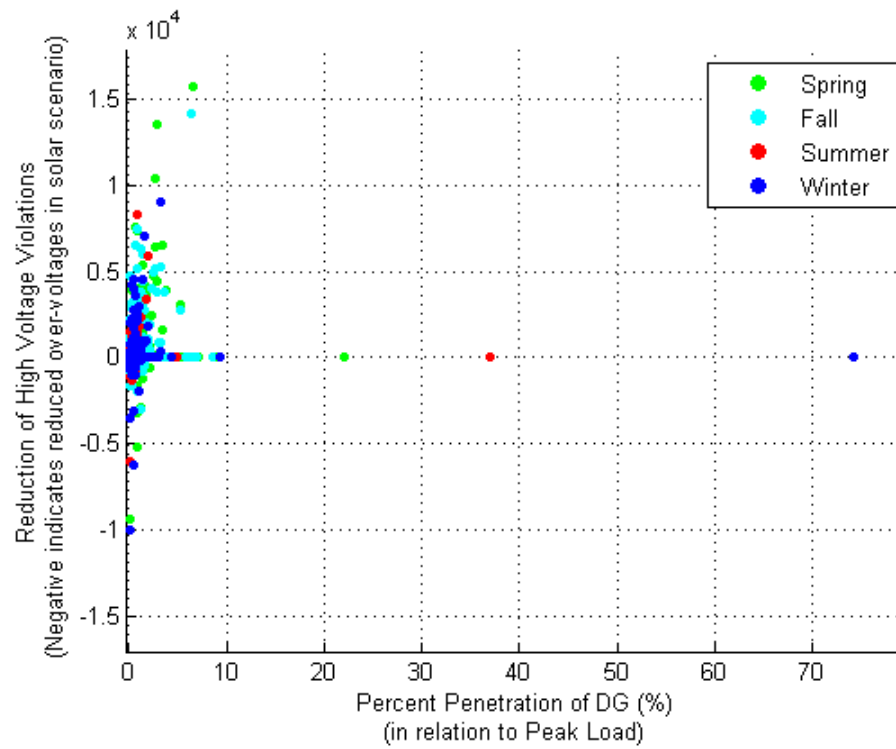
Figure 4.13 and Figure 4.14 show the change in low voltage violations as a function of DG size, while Figure 4.15 and Figure 4.16 show the change in high voltage violations. Again, a negative number indicates a reduction in the solar DG case. Low voltage violations tend to decrease during summer and winter months when the addition of solar DG increases the overall feeder voltage during low voltage periods (i.e., during high load periods). However, high voltage violations tend to increase during spring and fall months as the load is relatively low and the solar DG increases the voltage to a level that cannot be compensated, or is not detectable, by existing voltage control devices. These would need to be dealt with on a case-by-case basis (i.e., during the interconnection study). Possible solutions may be adjustment of current voltage control set points, use of seasonally adjusted voltage control set points, addition of sensor and control equipment, addition of new voltage control devices, or replacement of conductors.



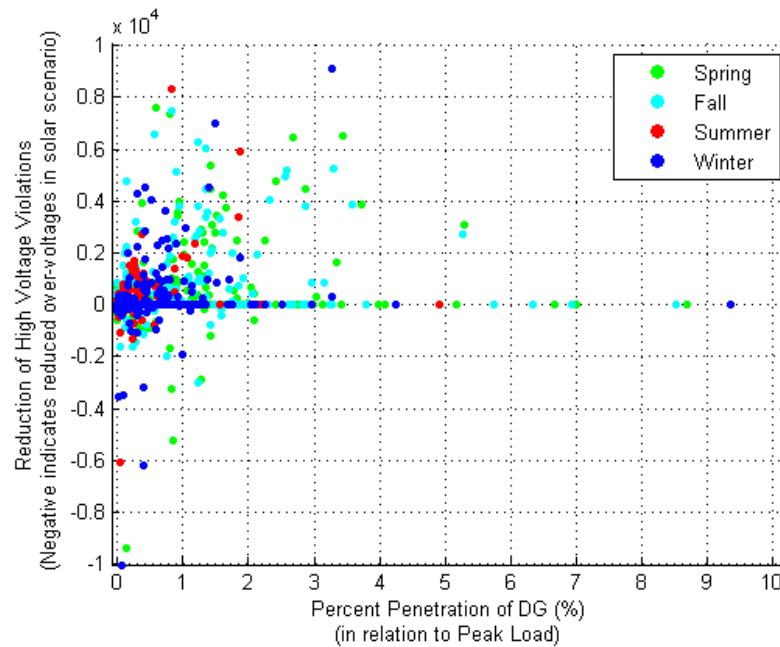
**Figure 4.13.** Change in Number of Low Voltage Violations versus Percent DG Penetration



**Figure 4.14.** Change in number of low voltage violations versus percent DG penetration (zoomed)



**Figure 4.15.** Change in Number of High Voltage Violations versus Percent DG Penetration.



**Figure 4.16.** Change in Number of High Voltage Violations versus Percent DG Penetration (zoomed)

DG modifies traditional voltage profiles of feeders. Understanding the impact to traditional voltage control devices and settings is important to prevent over- and under-voltage situations. A quality interconnection study will typically identify these issues prior to deployment and most concerns may be addressed through modification of current set points. In extreme high-penetration cases, additional voltage devices may be required; however, penetration levels will typically need to be very high to trigger this type of improvement. New measurement points at the point of interconnection may also identify voltage violations that were previously undetected, allowing for higher quality service.

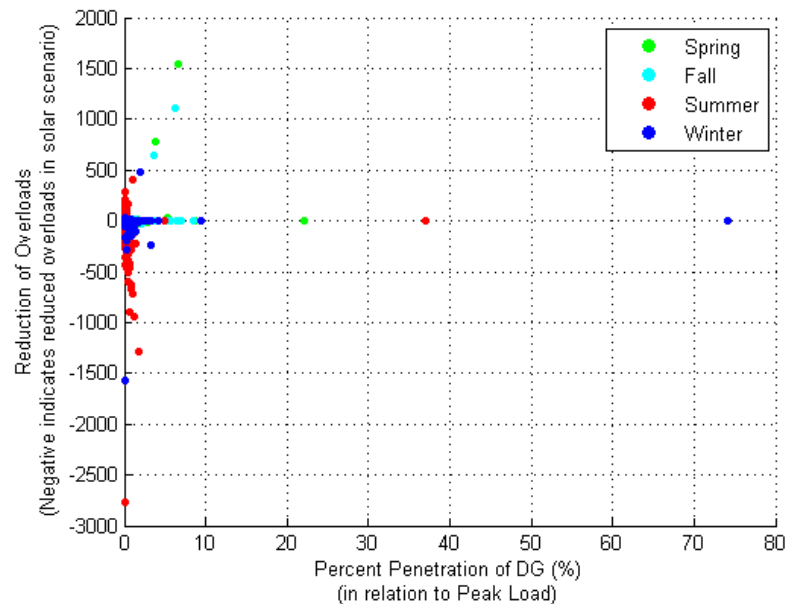
#### 4.4.1.3 Line and Transformer Overloads

Addition of solar DG changes the behavior of power flow on the system. If coincident with peak loads, it can reduce line flows and reduce the overall amount of time equipment is overloaded. In some cases, especially during low load periods, the addition of solar DG can reverse power and cause additional overloads, especially on local equipment. It should be noted that reduction of overloads may lead to deferral of capital investments, while an increase in overloads may trigger a need for capital improvements. In the case of high-PV penetration, reduction of overloads can typically only occur if the feeder is already near its capacity limit, in which case the solar production can offset the peak loads. An increase in overloads is typically driven by local transformer or conductor constraints, and would typically be detected during a cursory interconnection study.

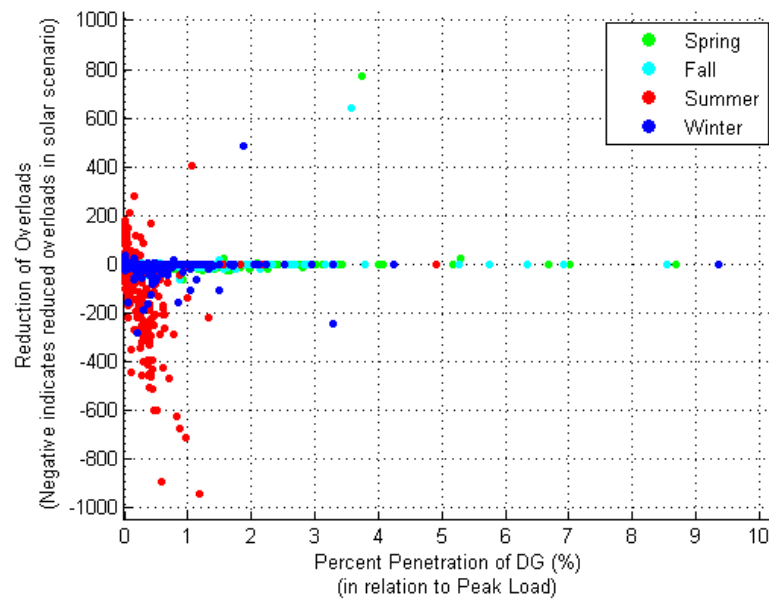
The studies performed by the Alstom DOTS were designed to count the number of overloads occurring on each segment of the feeder. Similar to over- and under-voltage measurements, these were counted as number of devices overloaded times the number of time steps overloaded. Again, this measurement is not ideal and hides some of the more detailed information, but does lead to general indications and trends. Additionally, the study looked at average load profiles and average solar profiles, where approximately 65 percent of the peak solar output was observed and variability in both the load and

solar is significantly decreased. These are not reflective of peak studies and indicate that the information produced may not be a good indicator of the effects on overloads.

As seen in Figure 4.17 and Figure 4.18, during summer months, the addition of solar DG reduces the number of overloads on a majority of feeders. Winter shows a few feeders with reduced overloads. Fall and Spring show much more varied results, but a majority of cases show no change. Overall, 8 percent of cases indicated an increase in overloads, 24 percent a decrease, and 68 percent no change. The change in overloads is highly dependent on penetration level, system topology, and load levels. Overloading effects should be evaluated on a case-by-case basis to determine if equipment needs to be upgraded.



**Figure 4.17.** Change in Number of Overloads versus Percent DG Penetration



**Figure 4.18.** Change in Number of Overloads versus Percent DG Penetration (zoomed)

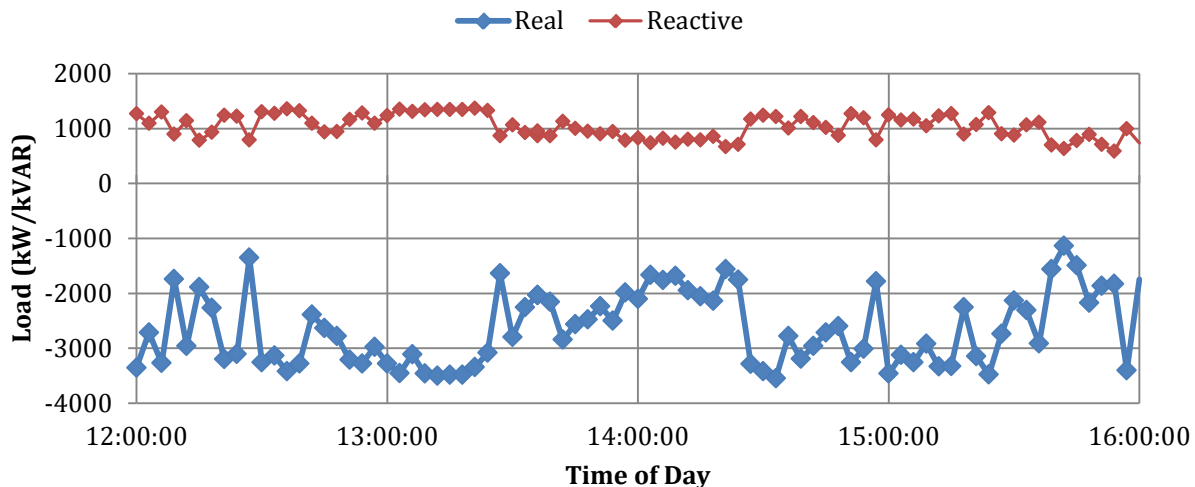
Overloads are addressed today through interconnection studies. However, it should be noted that the current process looks at each project individually and addressed the impacts it will have to the grid as the grid is known at that moment in time. As penetration levels increase and additional DG sites are developed, the current flexibility in the grid is absorbed. Future projects may have to bear the whole cost of upgrades needed to allow for the additional DG.

#### 4.4.2 Intermittency Study

During the four hours simulated at 3-minute intervals, a few key findings were observed. First, the solar installation supplied enough real power to service all real loads on the example feeder during the study period. In addition, reverse flow was seen at the feeder head and along the main line between the solar installation and the feeder head (approximately 4.8 MW of PV production while total load of approximately 1.2 MW). Flow is only reversed at the station power transformer (fixed tap) example feeder regulator and the VAR controlled capacitor. All other voltage control devices had forward flow due to the location of the generator.

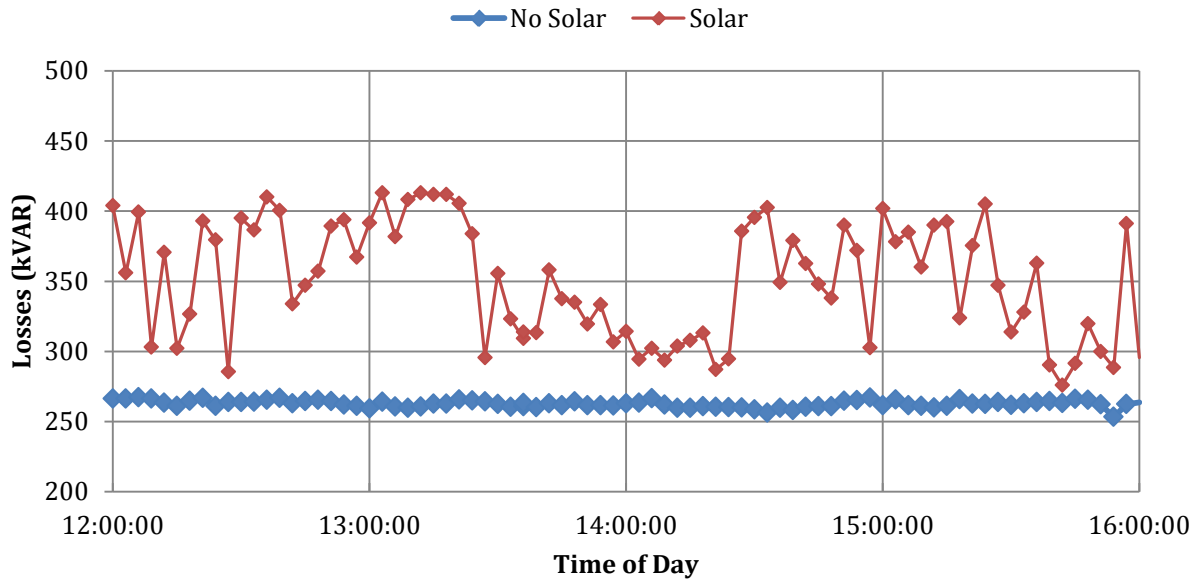
The presence of the solar PV installation significantly impacted feeder-head power factor due to the fact that the generator continuously consumed reactive power and the feeder under study has limited VAR compensation. The current solar installation does not have the ability (or requirement) to provide reactive power adjustments for VAR compensation. In most cases, it is required to absorb reactive power to keep local voltages levels from rising too high. Note, the power flow sign is indicated using real and reactive flow directions instead of the traditional “leading” or “lagging”. The average feeder-head power factor without solar was 0.9654 forward real power and forward reactive power, while the average feeder-head power factor with solar was 0.9274 reverse real power and forward reactive power.

The single VAR controlled cap on example feeder remained closed in throughout both solar and no solar simulations. Figure 4.19 shows the feeder-head real and reactive loading during the study interval. Assuming the conductor operating limits are properly defined, equipment overloads occurred on the three-phase overhead line segment between the generator interconnect re-closer and re-closer 164856867 when generator output approached peak capacity.



**Figure 4.19.** L1203 Feeder-Head Flows with Solar

The presence of the PV installation leads to an increase in real and reactive line losses. This is due to the increased branch flows which was in turn due to both large DG output relative to the current loading levels and increased VAR flow. The average line losses without solar was 177.2 kW and 262.5 kVAR, while the average line losses with solar were 196.8 kW and 350.8 kVAR, or a net change of 78.4 kWh and 353.2 kVAR-h in the four-hour period. Figure 4.20 shows with solar and without solar reactive line losses during the study period.



**Figure 4.20.** L1203 Reactive Line Losses

The presence of the PV installation leads to an increase in regulator operations over a wider range of positions. An operation is considered a single raise/lower step. Table 4.7 summarizes the changes in tap operations for each of the regulators. The average percent increase in operations for a given regulator was 187 percent and the average increase in tap position range for a given regulator was 3.87 taps. It should be noted that these results are during the “worst case” scenario of extremely low loading and extremely high solar output and solar variability. It is expected that the annual impact to regulator tap operations will be far less than shown during this four-hour period.

**Table 4.7.** Summary of Regulator Tap Operations during 4-hour Simulation

Regulator	Percent Change in Operations	Without Solar Tap Range	With Solar Tap Range
L1203	600%	2	8
39025809 B	85%	7	11
39025809 C	136%	3	8
39021413 A	264%	4	9
39021413 B	185%	3	10
39021413 C	85%	4	9
39025903 B	105%	6	6
39025903 C	36%	2	1

The results presented are only for a 4-hour period during the peak solar period of a low load day, representing the expected “worst case” scenario, so general conclusions applicable to other feeders across

all time periods are difficult to determine. However, specific to these four hours, it can be seen that the reverse power flow on the system causes a number of issues that may need to be addressed during the planning stages of the solar deployment at least on a feeder by feeder basis and potentially for all feeders. There is currently a significant amount of ongoing research to address these issues using active control of inverter reactive power output that may address this issue more efficiently.

## **4.5 Distribution Study Findings and Discussions**

### **4.5.1 Study Findings**

Overall, the addition of solar DG to simulated distribution feeders caused both benefits and impacts. The studies shown here attempt to determine general trends of benefits and impacts, rather than quantify specific values. The actual benefits and impacts seen are highly dependent on where the solar plant is connected on a particular feeder, how large the plant is compared to the load on the feeder, and on the topology of the feeder. As the location of future connections cannot necessarily be determined at this time, a best guess was made using the current interconnection queue then distributing the remainder in a systematic manner. While the individual results may not be perfectly accurate, the overall trends should be indicative of the benefits and impacts seen by the addition of solar DG. This is an indication that in the future interconnection studies may be of greater importance by not only evaluating the reliability and safety of new DG installations, but also the overall economic impact. These types of modifications require additional data, more intensive labor, regulatory involvement and possibly additional tools, and will tend to increase the cost and time of delivery for interconnection management. Alternatively, use of advanced inverters and controls can address many of the issues identified. If these are required by regulation or adopted as industry standards these problems will be isolated to installations installed without such devices.

During higher load periods, typically in the summer, both real and reactive losses decreased. During lower load periods, both real and reactive losses tended to increase, as highlighted by the intermittency study, or remain relatively unaffected. The overall trend indicates a reduction of losses equating to approximately 89 MWh per year per feeder. There was a wide variability among the feeders, some showing significant increases in losses and others significant decreases. While the average feeder experienced an 89 MWh reduction in losses (annually), the individual feeders ranged from 5124-MWh reduction to 6757-MWh increase in losses. It is expected that these outlier cases would be identified during an interconnection study and actions would be taken to decrease the impacts, including changing the interconnection point, upgrading of existing equipment, or a decrease in the size of the proposed solar installation. High reactive losses could be corrected by new capacitors, modification of existing capacitor set points, or evaluation of the solar installations reactive power requirements. However, each of these solutions has a cost associated with it, from increased labor and interconnection study costs to capital improvement projects, and should be evaluated on a case-by-case basis.

Equipment overloads tended to decrease due to the offset of local power flow. In localized high-penetration cases, however, this will need to be evaluated during the interconnection study to determine if the equipment is capable of handling the maximum reverse power flow. For example, in the intermittency study, a small section of line was overloaded for a brief period of time. However, this circumstance would likely be identified in a cursory interconnection study. The study should determine if

this is an acceptable overload or whether the installer should be required to upgrade the service drop or transformers.

Power factor tended to be negatively impacted, due to decreased real power flow and sinking of reactive power at the solar installation (to prevent over-voltage). This may require evaluation of current capacitor settings or a re-evaluation of the solar installations reactive power requirements. In the future, the use of smart inverter technology may be required by solar installers to allow reactive power export settings to offset the sinking of reactive power.

The Alstom DOTS performs successive time interval simulations (at 3-minute intervals) to represent the time-series behavior of the load, solar generation, and line regulators. This provides an indication of the impact to regulator lifetime by successively calculating the requisite tap position at each time interval. However, because the tool does not store the previous tap position, does not consider timing delays in regulator actions, and the time interval is greater than most tap changing intervals, it is only indicative of an increase in tap operations. Previous work has shown that using longer time intervals in simulations underestimates the impact on regulators when studying solar DG [1]. The time step of the simulation (and input data) should ideally be shorter than the timing interval of the regulator controls (approximately 30 seconds to 1 minute).

With these caveats, the simulations show a 187 percent increase in regulator tap operations during the four-hour period. This increase would indicate a reduction of the asset life by 54 percent during the simulated four-hour period. However, the overall impact is far less. In the worst case, this change would be seen during all daylight hours in a year, resulting in a 27 percent reduction of regulator lifetime. In most likelihood, this value is even less due to the extreme variability of the solar input during the four-hour simulation. However, more detailed studies have shown impacts as high as 500 percent on an annual basis in extremely high-penetration scenarios [1]. In the industry, most utilities evaluate the regulator life based upon the number of times it will operate. As shown by this study, the system regulator operations will increase, which in turns reduces the asset life. However, the severity of how quickly any individual PV site impacts the regulator life depends on where the PV installation is located, location of the regulator, and load on the circuit. Therefore, it is important that each interconnection captures the impact to the regulator and determine cost impacts for that individual project. In the future, smart inverter technology may be available to reduce tap changing operations on substation or line equipment by actively managing reactive power output to maintain voltage levels.

#### **4.5.2 Additional Considerations**

A number of benefits and impacts were intentionally not addressed during this report and were considered out-of-scope. This section discusses a few issues that were not addressed and left as open questions for future evaluation.

Many utilities will use fast reclosing after a fault is cleared. This reduces the momentary outages a customer experiences. However, this also magnifies the impact of potential islanding by high-penetration PV or other DER. Utilities have installed a technique called “hot line blocking” which uses either a dead bus relay (lowest cost) or a synch-check relay (higher cost) to detect if the DER has disconnected from the grid prior to reclosing after a fault. This assures that the DER is not online and out of phase with the grid during the reclosing, but requires additional planning and costs. In general, anti-islanding or islanding detection can be the most expensive modifications needed for DG on a distribution system.

These costs can be either absorbed by the utility, or more commonly the last generator system to be installed on the distribution system that causes the system to require islanding detection or anti-islanding equipment, paying the entire cost of the system. This will likely limit the penetration on a feeder. Some equitable method of cost allocation is needed to spread these costs among all solar or DER on the feeder. Further research on the extent of this issue and its costs is necessary to clarify its significance as a potential regulatory issue.

There are a number of outstanding issues surrounding fault detection, isolation, and temporary reconfiguration that were not addressed in this study. Significant research is currently underway to estimate these impacts and provide general guidelines for addressing these concerns in a cost-effective manner. In some cases, it is as simple as a re-evaluation of current protection set points. At higher penetration levels, it may require the re-design of current protection schemes. Inverter performance testing may also become necessary to verify the performance of inverters during certain events. Additionally, the change in visibility into the operational system via the DMS has an impact on the ability to reconfigure the system during outages; the output of solar DG may mask the amount of load currently on the system and cause further outages during restoration. However, if properly managed, solar DG may be used to more quickly restore customer service; ongoing research is attempting to address these issues.

Future applications may benefit from the use of smart inverters to compensate for local voltage variations or to supply or sink reactive power as needed. However, there are a number of issues that must be addressed. First and foremost is the ability to smoothly and reliably control the reactive power output of distributed devices while not disrupting normal operations; research is ongoing in this area. Equitable arrangements will need to be made to fairly compensate the inverter owners for allowing control of their reactive output; this may range from requiring owners to participate to performance-based compensation through an ancillary service contract.

Impacts to the performance of other technologies may also need to be evaluated. For example, Coordinated Volt-VAR Control (CVVC) or Conservation Voltage Reduction schemes may be impacted by solar DG as the voltage variability is increased. However, there is also the potential to use smart inverters to increase the efficacy of CVVC schemes by providing more fine-grain local voltage control. Many utilities, including Duke Energy, are deploying Integrated Volt-VAR Control (IVVC) and Demand Side Demand Management (DSDM) to manage voltage. Understanding how IVVC and DSDM will operate with higher levels of DG penetration needs to be further studied to develop future management requirements. Additional control devices may need to be deployed on the grid to further maintain voltage within ANSI standards. Traditionally, a utility's primary focus for voltage regulation was during peak periods. This study has shown that the presence of DG makes light load periods more prone to voltage disturbances.

Bi-directional meters, and the ability to include additional metrics such as peak demand, peak output, and reactive energy, may be beneficial in the future. This may allow the utility and device owners to equitably receive and pay for services that are typically hidden by current net-metering standards.

While all of these issues were out-of-scope for this study, they should be considered for future evaluation or on a case-by-case basis. Each of these may affect the overall cost to the installer or to Duke Energy.

## 5.0 Conclusions

The study found that system net-load variability increases with PV penetration. With PV penetration increasing to 20 percent of peak load in the integration cases, system DA planning reserve requirements (not including contingency reserve) increase 30 percent, and RR requirements increase 140 percent compared to the values without PV (reference cases). The Duke Energy system was able to maintain reliable operations in dispatch simulations, evaluated in terms of meeting ancillary service requirements and the target compliance level with NERC CPSs, with the caveat that contingencies were not modeled. Under the study conditions, Duke Energy's generation fleet proved to be capable of accommodating PV with an installation capacity of up to 6800 MW, the highest level investigated in this study. The PV integration cost ranges from \$1.43 to \$9.82 per MWh of PV energy, in comparison with reference generation cases, resulting from the additional reserves and cycling of conventional generators to compensate for PV variability. The results exhibit a trend of increasing unit PV integration cost at successively higher PV levels, consistent with other similar studies [3][4].

It should be noted that projected PV system sizes and locations, future load growth, resource mix and fuel prices, are a few assumptions with great impact on study results. Refined model assumptions, additional validation of modeling tools, and improved study procedure should be attempted in future studies. The same set of assumptions and models which affect study results significantly also point to the directions of operation and technology improvements for a smooth transition toward the high-PV energy mix. The improvements can be categorized into the two target areas: increase fleet flexibility and reduce uncertainty and variability. Efforts to make these improvements are certainly not free. Nonetheless, the attempts should be worthy if their costs are a fraction of the potential PV integration costs.

The transmission analysis was based on four seasonal day "snapshots," a common approach for transmission planning at Duke and elsewhere. Because PV supplies real and reactive power, the voltage magnitude at sub-transmission buses where the distributed energy from PV sources is aggregated has an increase in voltage magnitude proportional to the amount of PV output. The most affected areas in the Duke system are Areas 12 and 13 in the 44-kV systems where voltage magnitude violated the upper limit in the spring and fall cases. Voltage control devices modeled in the transmission system appeared unable to handle this over-voltage. Distributed PV introduces voltage control challenges during light load conditions, which suggests mitigation measure warrant further investigation. Reduction in transmission losses was identified, although the amount of energy loss reduction in the transmission network resulting from distributed PV depends on many factors such as the type of the conductors in the system, PV real power outputs and associated power factor, and the nature of load. For the four power flow snapshots analyzed, transmission loss reduction due to PV were between 2.6 and 5.7 percent as a percentage of PV output. The loss reductions observed would reduce generating requirements proportionally, which will offset some of the generating cost increases noted. Both should be factored into PV avoided costs analyses.

Overall, the addition of solar DG to simulated distribution feeders caused both benefits and impacts. The simulated distribution feeders experienced greater voltage fluctuations on feeders servicing PV installations, sometimes experiencing reverse power flows and more voltage control actions by voltage regulation devices. During higher load periods, typically in the summer, both real and reactive losses decreased. During lower load periods, both real and reactive losses tended to increase, as highlighted by the intermittency study, or remain relatively flat. The net benefit is very dependent on feeder topology,

penetration level, and interconnection point, and should be evaluated on a case-by-case basis before assigning associated costs or benefits. Equipment overloads tended to decrease due to the offset of local power flow by local generation, but in a few cases additional overloads were experienced mainly due to reverse power flows. In a few cases, substation power factor was negatively impacted; this may require evaluation of current capacitor settings, re-evaluation of solar installations' reactive power requirements, and in the future, perhaps the coordinated use of smart inverter technology by solar installers. It is expected that both overloads and reactive power requirements would be addressed in thorough interconnection studies. With PV power on the system, regulator operations tended to increase, which in turn reduces asset life. However, the severity, or how quickly any individual PV site impacts the regulator life, depends on where the PV installation is located, its relative size, and the load on the circuit, among other factors. Therefore, it is important that each interconnection study captures the impact to the regulator and determine cost impacts for that individual project. If it becomes necessary for interconnection studies to thoroughly assess the economic benefits and impacts (beyond safety and reliability) of individual installations, it is expected that interconnection costs will increase and new tools may be needed.

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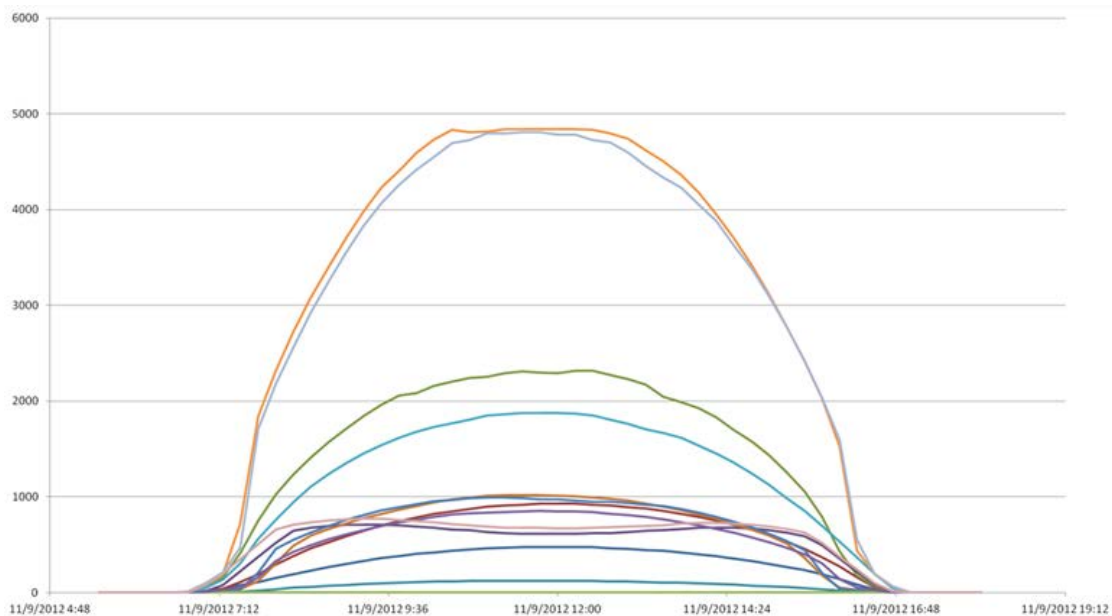
**Appendix A**  
**Generation Study**

## Appendix A

### Generation Study

#### A.1 PV Data Calibration

As shown in Figure A.1, the fleet is made up of systems having different sizes, orientations, and other attributes. The largest system (in orange) is capped at its maximum inverter rating. Two systems (peach and purple) are seen to be tracking systems by the characteristic mid-day “droop.” Actual fleet output is the sum of all of these systems, representing the diversity of design configurations and geographic locations.



**Figure A.1.** DEP Sample Systems

In the absence of design configuration information, a translation between fixed, south-facing systems (as modeled) to fleet shape was made through a “calibration” process. This process used a sample set of output from measured PV systems as summarized in Table A.1.

**Table A.1.** Summary of Data Used for Calibration

Available systems with measured data	9	30
Selected systems with measured data (based on data availability)	8	14
No. clear sky days used	7	10
Number of distinct 1-kW systems matched to measured systems	8	11
Time interval	3-min	15-min

The calibration process was as follows:

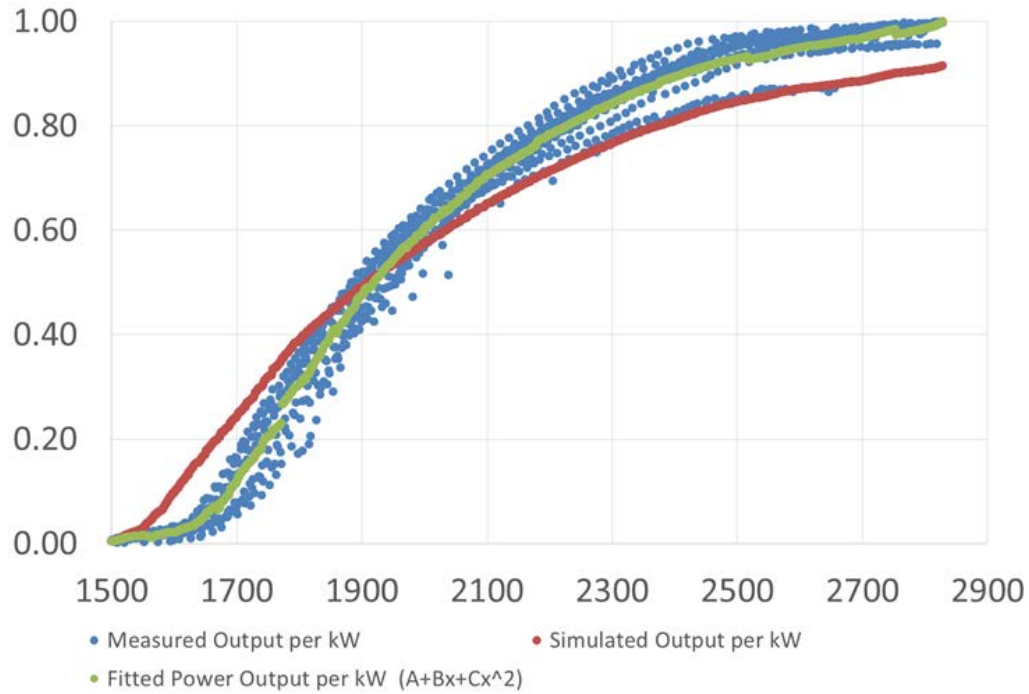
1. Simulate 1 kW systems
2. Find 5-10 clear sky days with data available for all measured systems
3. Compress time interval (3-minute or 15-minute) on simulated data
4. Aggregate measured and simulated (closest systems)
5. Calculate fitting function for lowest overall error

The fitting function was of the form:

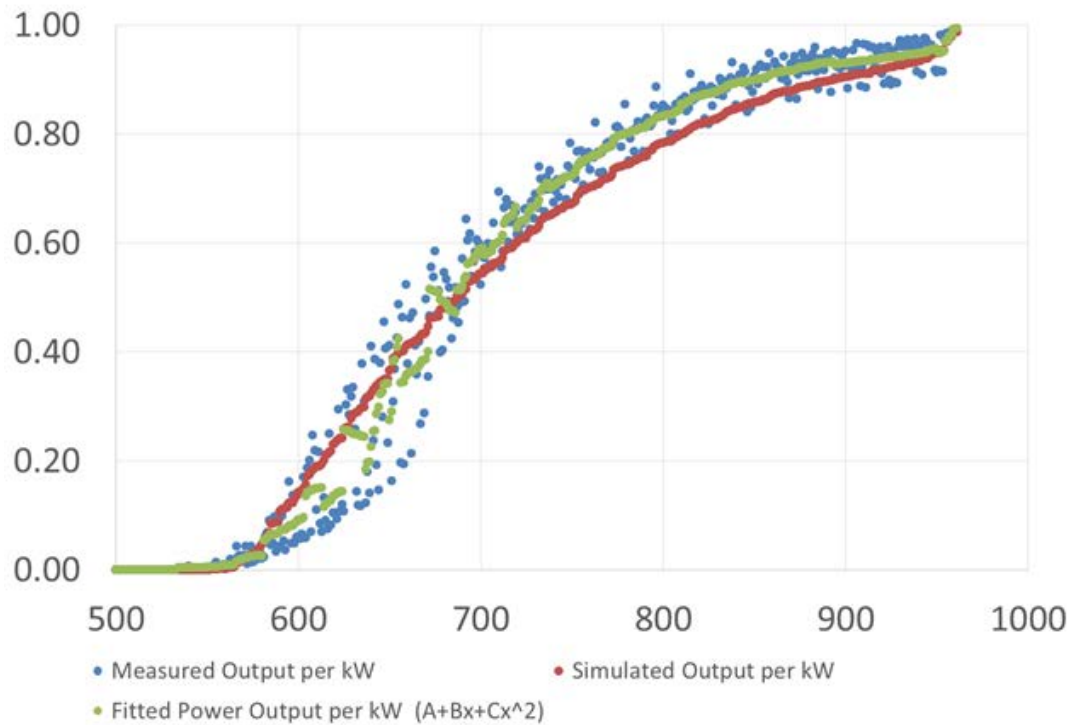
$$\text{Corrected power} = A + Bx + Cx^2$$

where x is the simulated power. Coefficients were calculated independently for each of 20 bins (0 to 0.05 kW, 0.05 to 0.10 kW, ...) and for each fleet (DEC and DEP) to minimize error between normalized aggregate measured output and normalized aggregate modeled output. Measured, modeled, and fitted data are all shown in Figure A.2 and Figure A.2.

Calibration coefficients were applied to every 1-kW system in fleet (both 1-hour and 1-minute data), and this calibrated data was delivered for the project. The scaled and aggregated fleet data then reflected the calibrated results from individual systems.



**Figure A.2.** Comparison between Measured and Simulated PV Fleet Power Production (DEC)



**Figure A.3.** Comparison between Measured and Simulated PV Fleet Power Production (DEP)

## A.2 Automatic Generation Control

### A.2.1 Methodology

The objective of AGC is to balance load and generation in real time to the degree required by the NERC CPS. The target of AGC is to contain the area control error (ACE). ACE has two major components: 1) unscheduled interchange and 2) the response of the balancing area to frequency deviations. In this work, because only one balancing area is considered in the simulation, the difference between area generation<sup>1</sup> and area load is an accurate target for AGC to minimize.

Figure A.4 and Figure A.5 show the diagram for real-time dispatch and AGC, respectively. As shown in Figure A.4, real-time dispatch is performed based on the difference between the hourly generation schedule and real-time net area load forecast. Net area load is the area load minus variable generation. Through economic dispatch of the generation resources participating in real-time dispatch (also called load-following resources), adjustments to the hourly schedule of these resources can be calculated, which is called the real-time dispatch signal. The adjusted schedule is called the real-time schedule. The way in which hourly schedules are determined, how often RTD is performed, and the look-ahead time of the real-time forecast can all be configured according to the system being modeled.

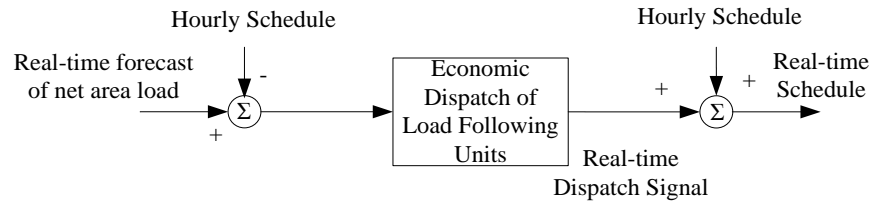
As shown in Figure A.5, the difference between net area load and total area generation determines the raw ACE. The control ACE is derived from an ACE filter and a controller applied to the raw ACE, which is then allocated to each AGC generator based on economics, ramp properties, or a pre-calculated ratio. Therefore, the setting of generator operation point is the sum of real-time schedule and the regulation signal. Combined with information from Figure A.4. Diagram for Real-Time Dispatch Simulation, we have:

$$\text{Operation Point} = \text{Hourly Schedule} + \text{Realtime Dispatch Signal} + \text{Regulation Signal} \quad (\text{A.1})$$

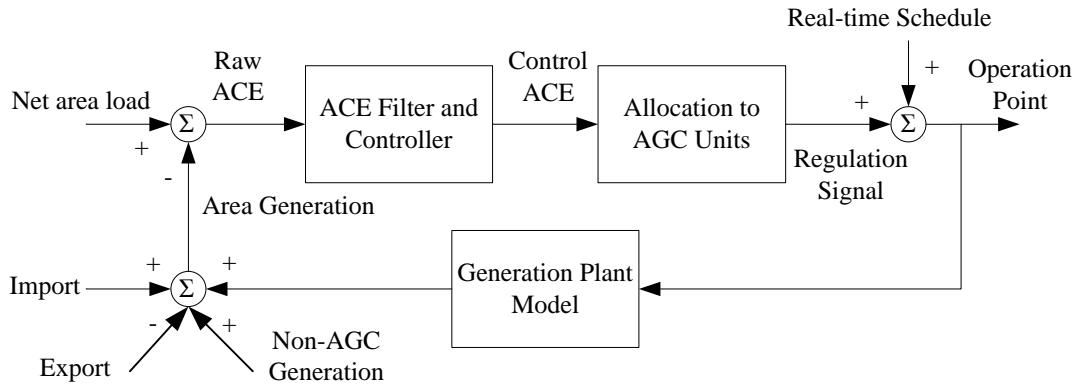
The actual outputs of AGC generators are based on the operation point settings subject to the properties and constraints applied by the generation plant model. Slow governor dynamics, ramping constraints, and generation control errors can be simulated in the generation plant model if desired. The total area generation depicted in Figure A.5 includes the effects of area imports and exports. When no separate RTD process is simulated (which is the case for the NV Energy southern system), real-time schedule is replaced by hourly schedule of generation resources before adding the regulation signal, and economic dispatch is performed inside the AGC controller.

Design of AGC logic is of great practical value and has been a research topic for decades. While the main objective of AGC is balancing generation and load in real time, the algorithm also has goals of minimizing the number of AGC pulses, the number of AGC pulse reversals, etc., to reduce generator wear resulting from regulation service. The following two sections will describe the ACE filter and controller adopted in the ESIOS program to simulate the NV Energy southern system. Other AGC algorithms also can be used in ESIOS to model a different system or to simply test their performance.

<sup>1</sup> The term “area generation” here refers to all generation used to meet the balancing area’s load, which includes the net interchange as well as generation inside the balancing area.



**Figure A.4.** Diagram for Real-Time Dispatch Simulation



**Figure A.5.** Diagram for AGC Simulation

It should also be pointed out that exactly replicating the AGC in the NV Energy southern system was not deemed necessary by the study team, because AGC logic normally can be tuned to achieve a wide range of desired control performance within the AGC generators' capability. A representative AGC implementation is sufficient for the study of generator fleet flexibility affected by both generator characteristics and unit commitment and scheduling results. If testing the AGC logic is the main goal of simulation, duplicating the exact AGC logic in ESIOS becomes necessary.

### A.2.2 ACE Filtering

A low-pass filter is used to smooth the raw ACE to remove measurement noise and reduce unnecessary movement of AGC generators. The filter design in ESIOS mimics approximately the one in the NV Energy southern system and can be represented as the following.

$$\text{Raw ACE: } ACE_t = \text{generation}_t - \text{load}_t \quad (\text{A.2})$$

$$\text{Smoothed ACE: } SACE_t = (1-a)*SACE_{(t-1)} + a*ACE_t \quad (\text{A.3})$$

In Equation (A.3),  $a$  is a variable ranging between 0 and 1, which specifies the weight of raw ACE from the present time step. The value of  $a$  can be adjusted to control how fast AGC resources follow the raw ACE.

### A.2.3 ACE Controller

The smoothed ACE (SACE) at the output of ACE filter is then processed to generate the control ACE before allocation among AGC resources. The control ACE is calculated by:

$$CACE = RACE + EACE \quad (A.4)$$

in which RACE is called regulation ACE and EACE emergency assist ACE. RACE and EACE are determined by applying different gains on the smoothed ACE according to the ACE control regions described below:

1. Normal: When  $\text{abs}(SACE) < \text{REGDB}$ , regulation and emergency assist ACE are both 0; that is,  $RACE = 0$  and  $EACE = 0$
2. Regulation: When  $\text{REGDB} < = \text{abs}(SACE) < = \text{EADB}$ ,
 
$$RACE = (SACE - \text{REGDB}) * K_R, \text{ if } SACE > 0;$$

$$RACE = (SACE + \text{REGDB}) * K_R, \text{ if } SACE < 0; \text{ and}$$

$$EACE = 0$$
3. Emergency assist: When  $\text{abs}(SACE) > \text{EADB}$ ,
 
$$RACE = (\text{EADB} - \text{REGDB}) * K_R, EACE = (SACE - \text{EADB}) * K_A, \text{ if } SACE > 0; \text{ and}$$

$$RACE = -(\text{EADB} - \text{REGDB}) * K_R, EACE = (SACE + \text{EADB}) * K_A, \text{ if } SACE < 0$$

in which REGDB is the regulation dead band (e.g., 12 MW), EADB is the emergency assist dead band (e.g., 25 MW), and  $K_R$  and  $K_A$  are the proportional coefficients for the regulation and emergency assist regions, respectively. Example values for  $K_R$  and  $K_A$  are 0.8 and 1.0. Values of the regulation and emergency dead bands, coefficients  $K_R$  and  $K_A$  can be tuned to achieve the desired control performance.

## A.3 Operator Dispatch Model

### A.3.1 Methodology

The objective of the operator model is to simulate the manual dispatch actions performed by operators that are necessary to maintain required operating reserves and control performance. Because of the variability and uncertainty with load and variable generation, the computerized balancing processes (AGC and RTD) may not be capable of following real-time changes of net load, especially in high VG penetration cases. The operator model in ESIOS monitors regulation and spinning reserves available on the system, and adjusts them by starting peaking units and re-dispatching non-regulating AGC units. Other functions, such as the commitment of additional large generators or de-commitment of online generators, could also be performed in the operator model but currently are not implemented.

The operator model estimates the average regulation and spinning reserves available during a specified time period.<sup>1</sup> When regulation up (RegUp) reserve is estimated to be insufficient, generators without regulation capability are raised by the amount of shortage until their maximum capacity is reached; when regulation down (RegDn) reserve is insufficient, either non-regulation generation has to be lowered or a CC generator has to switch from  $2 \times 1$  to  $1 \times 1$  mode. Considering the restart of a CT takes nearly 2 hours, turning off CT simply to increase RegDn reserve for a short period may not be prudent. Therefore, the program currently only lowers non-regulation generators to resolve the shortage of RegDn reserve. Non-regulation generators that have been dispatched off schedules by the operator model will be checked regularly to determine whether regulation reserves would be sufficient if these generators returned to their operating schedules.

Peaking units are turned on when a shortage of spinning reserve is predicted, or when RegUp reserve is insufficient and there is no head-room on non-regulation units. On the other hand, peaking units are turned off when they are not needed so that system efficiency can be improved and RegDn reserve is increased simultaneously.

The following functions are included in the operator model:

- Spinning reserve check and adjustment
  - Turn on peaking units if spinning reserve is insufficient. Spinning reserve requirement is determined dynamically based on the output of the largest online generator and the share and obligation of the balancing authority (BA) within the reserve sharing pool.
- RegUp reserve check and adjustment
  - Increase Non-Reg generation when more RegUp is needed, or return Non-Reg generation back to schedule when RegUp is sufficient.
  - Turn on peaking units if Non-Reg generation adjustment is insufficient to resolve RegUp shortage.
- RegDn reserve check and adjustment
  - Decrease Non-Reg generation when RegDn is needed, or return Non-Reg generation back to schedule when RegDn is sufficient.
- Turn off peaking units when conditions allow.

### A.3.2 Startup and Shutdown of Peaking Units

The operation of peaking units for the purpose of maintaining regulation and spinning reserves is described in details below.

#### 1. Available reserve calculation

- Available RegUp at time  $t$  is calculated by:

<sup>1</sup> In principle, the spinning reserve requirement should be satisfied in every moment in actual operations. The average available spinning reserve is used in the simulation to compare against the requirement to avoid frequent dispatch of peaking units caused by instantaneous reserve shortages.

$$R_{Up_t} = P_{Reg\_max_t} - P_{Reg\_Gen_t}, \quad (A.5)$$

where  $P_{Reg\_max_t}$  is the maximum regulation units capacity available at time  $t$ , and  $P_{Reg\_Gen_t}$  is the total regulation units output at time  $t$ .

- Available RegDn at time  $t$  is calculated by:

$$R_{Dn_t} = P_{Reg\_min_t} - P_{Reg\_Gen_t}, \quad (A.6)$$

where  $P_{Reg\_min_t}$  is the minimum regulation units capacity available at time  $t$ .

- Available spinning reserve at time  $t$  is calculated by:

$$S_t = P_{max_t} - P_{Gen_t}, \quad (A.7)$$

where  $P_{max_t}$  is the maximum generation capacity of all online units available at time  $t$ , and  $P_{Gen_t}$  is the total online generation at time  $t$ .

## 2. Peaking unit activation

The available reserves calculated from step 1 will be compared to the corresponding requirements. If a shortage of regulation reserves (RegUp or RegDn) is detected, the operator model will first check if non-regulating AGC units can be adjusted to increase the reserves. Manually moving non-regulating units upward will increase RegUp. Moving them downward will help with RegDn. If there is no head room on non-regulating AGC units but still more RegUp is needed, then peaking units need to be started:

$$\text{If } R_{Up_t} < R_{Up_{min}} \text{ and } L_t < LF_t^x, \text{ then activate peaking unit } N, \quad (A.8)$$

where  $R_{Up_{min}}$  is the required RegUp reserve,  $L_t$  is the net load at time  $t$ , and  $LF_t^x$  is the net load forecast for the next  $x$ -minute interval produced at time  $t$ . This condition means that, if available RegUp reserve is less than the requirement and the load is increasing, then a peaking unit is started.  $N$  is a peaking unit identifier (ID). Peaking units are ordered according to production cost, and started from the cheapest one. The value assigned to  $x$  can range from 0 to 0.5 (hours) to avoid frequent on/off operation of units.

If spinning reserve is found insufficient, peaking units will be started directly:

$$\text{If } S_t < S_{min} \text{ and } L_t < LF_t^x \text{ then activate peaking unit } N, \quad (A.9)$$

where  $S_{min}$  is the required spinning reserve.  $S_{min}$  is calculated as the following:

$$S_{min} = \max\left(\frac{1}{2}P_{Gen_{k_t}} + (P_{Gen_{k_{max}}} - P_{Gen_{k_t}}) - S_{Share}, S_{Obligation}\right), k = 1 \dots M, \quad (A.10)$$

where  $P_{Gen_{k_t}}$  is the output of the  $k$ th online generator,  $P_{Gen_{k_{max}}}$  is the maximum output of this generator,  $S_{Share}$  is the spinning reserve share for NV Energy from a reserve sharing pool,  $S_{Obligation}$  is the obligated amount that NV Energy needs to provide to the pool, and  $M$  is the total number of online generators. Equation (A.10) means the total system spinning reserve needs to be larger than half of any online generator's output plus the reserve it carries, minus the share the BA gets from the reserve sharing pool. It also needs to be larger than the reserve obligation that the BA needs to provide to the pool in case of emergency in other systems in the pool.

## 3. Peaking unit deactivation

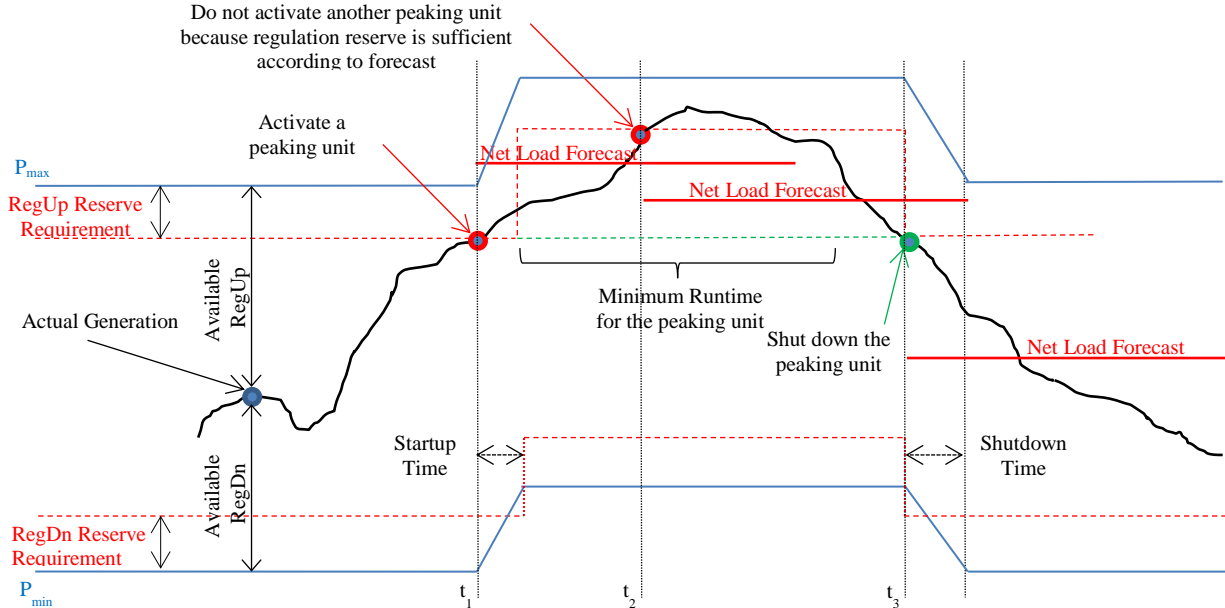
The following conditions will be constantly checked by the operator model. Peaking units will be shutdown to improve system efficiency if these conditions are satisfied simultaneously:

$$\begin{aligned}
 t - t_{start_N} &\geq MinRuntime_N \\
 HS_{NextHour_N} &= off \\
 R_{Up_t} - P_N &> R_{Up_{min}} \\
 S_t - P_N &> S_{min}, \text{ and} \\
 L_t &> LF_t^x,
 \end{aligned} \tag{A.11}$$

where  $t_{start_N}$  is the time when peaking unit N is started,  $MinRuntime_N$  is the minimum runtime of the peaking unit,  $HS_{NextHour_N}$  is its schedule in the next hour, and  $P_N$  is its current power output. These conditions state that when a peaking unit is to be turned off, it must have run longer than its minimum runtime, the next hour's schedule must be off, reserve requirements are still satisfied after it is off, and load shall be decreasing.

Alternatively, available reserves  $R_{Up_t}$ ,  $R_{Dn_t}$ , and  $S_t$  can be calculated for the period from time  $t-k1$  to  $t+k2$  and then compared to the predefined reserve requirement in the above steps. Parameters  $k1$ ,  $k2$  and forecast horizon  $x$  can all be configured to achieve optimal operation performance.

The process is illustrated in Figure A.6 using RegUp as an example.



**Figure A.6.** Peaking Unit Operation Approach

Operator actions for the peaking units shown in Figure A.6 are described below:

- Time  $t_1$ . Available RegUp reserve becomes less than the amount required and net load forecast for the next  $x$ -minute interval is higher than the actual net load at the moment (i.e., net load is

increasing) . Therefore, peaking unit 1 is started. Both  $P_{\max}$  and  $P_{\min}$  of online generation are increased.

- Time  $t_2$ . Available RegUp reserve becomes less than its requirement again, but net load forecast for next x-minute interval is lower than the actual net load currently (i.e., net load is decreasing). Therefore, there is no need to start another peaking unit.
- Time  $t_3$ . RegUp reserve becomes sufficient even after the peaking unit is shutdown, and net load forecast is lower than the actual net load at the moment (i.e., net load is decreasing). The time since the peaking unit is started has exceeded its minimum runtime. Therefore, the peaking unit can be shut down.  $P_{\max}$  and  $P_{\min}$  of online generation are reduced consequently.

#### A.4 Day-ahead Load Forecast Error Model

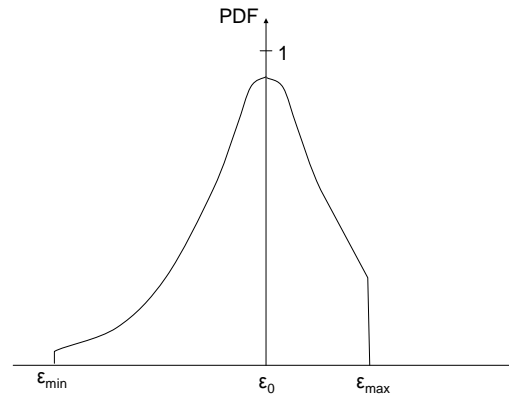
We use a truncated normal distribution (TND) method to generate day-ahead (DA) load forecast errors to mimic Duke's forecast error statistics. A TND is used because in normal distribution the range of data values is infinite, which is certainly not true for forecast errors. The probability density function (PDF) of the TND is expressed by the following formula:

$$PDF_{TND}(\varepsilon) = \begin{cases} 0, & -\infty \leq \varepsilon < \varepsilon_{\min} \\ \frac{PDF_N(\varepsilon)}{\int_{\varepsilon_{\min}}^{\varepsilon_{\max}} PDF_N(\varepsilon) d\varepsilon}, & \varepsilon_{\min} \leq \varepsilon \leq \varepsilon_{\max} \\ 0, & \varepsilon_{\max} \leq \varepsilon \leq +\infty \end{cases} \quad (A.12)$$

where  $PDF_N(\varepsilon)$  is the PDF of the normal distribution:

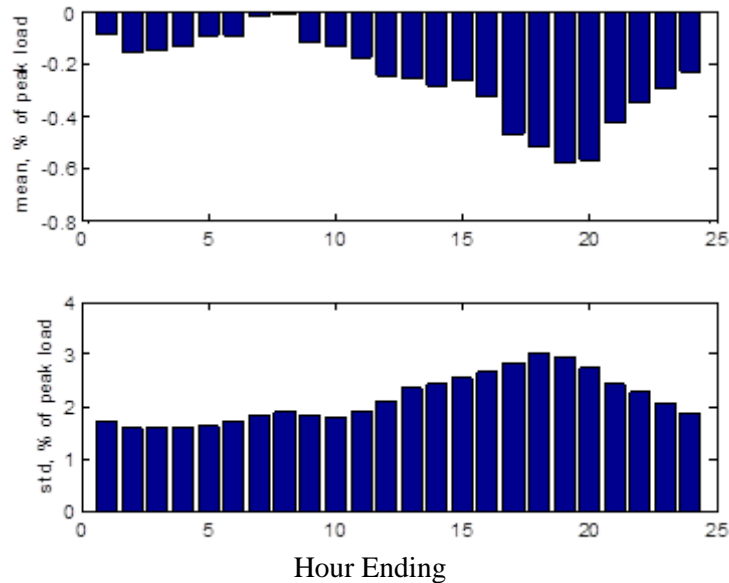
$$PDF_N(\varepsilon) = \frac{1}{\sqrt{2\pi}\sigma} e^{-\frac{1}{2}\left(\frac{\varepsilon - \varepsilon_0}{\sigma}\right)^2}, \quad -\infty \leq \varepsilon \leq +\infty \quad (A.13)$$

Figure A.7 illustrates the PDF of a TND series.



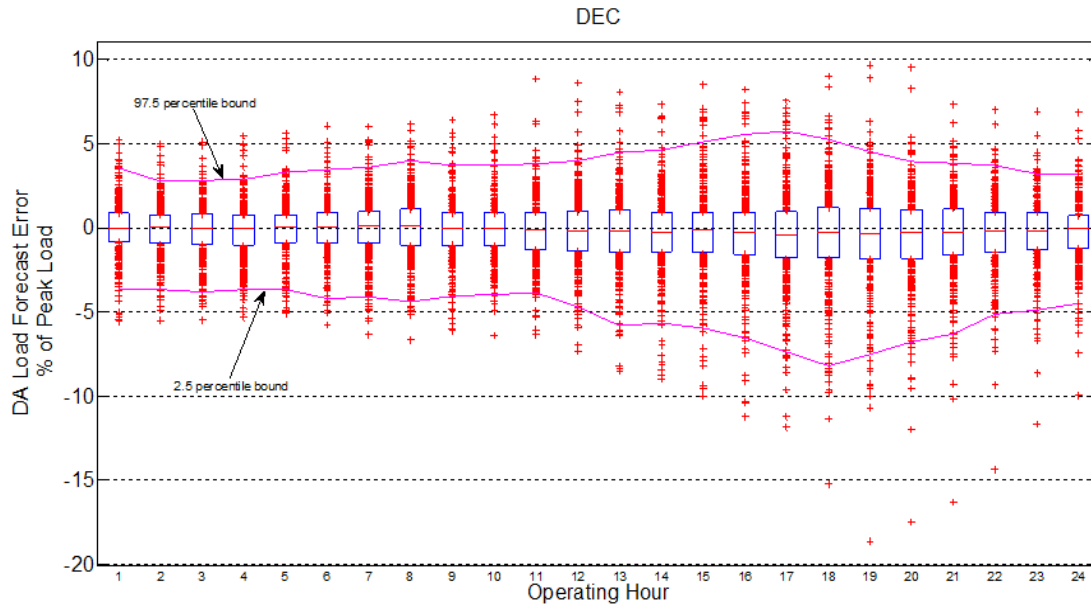
**Figure A.7.** PDF of Truncated Normal Distribution

Parameters of TND, such as mean  $\varepsilon_0$ , standard deviation  $\sigma$ , maximum error  $\varepsilon_{\max}$  and minimum error  $\varepsilon_{\min}$  should be consistent with the statistical features of the actual forecast. The statistics used for DA load forecast errors are calculated using historical values, in percentage of system annual peak load, which are shown in Figure A.8.



**Figure A.8.** Statistics of DEC Day-ahead Load Forecast Error by Hour

In the construction of the forecast error time series, the median value and standard deviation of historical forecast error data are used as the mean value and standard deviation, and the 2.5th and 97.5th percentile as the minimum and maximum values of the truncated normal distribution. The objective is to minimize the impact from big outliers. Figure A.9 shows the range of DEC forecast error by hour.



**Figure A.9.** Range of DEC Day-ahead Load Forecast Error by Hour

To create DA load forecast, the following steps are followed:

1. For each hour in the entire time series, generate the hourly average of actual load using the 1-minute load data.
2. Generate the forecast errors using a random series with TND; the statistics (mean and standard deviation) is shown in the above figure.
3. Subtract the forecast errors generated in step 2 from the hourly average generated in step.
4. After generating the time series of load forecast, add 20 minutes inter-hour ramps to data obtained from step 3, mimicking the actual Duke DA schedule.

## A.5 Day-ahead PV Forecast

The method used for generating DA PV forecast errors is similar to that for system load. However, the PV forecast is largely affected by the clearness index (CI) and should be limited to the max PV output of each operating hour. The following procedures are used for generating PV DA forecast data.

1. Generate the hourly average of actual PV using the 1-min data;
2. Calculate the clearness index value,  $CI = \text{Hourly Average} / \text{max output in this hour}$
3. Based on the CI level, use different statistics to generate forecast errors with the TND method.

$CI \leq 0.2$

Mean: 0     STD: 10% of the max PV output of each particular operating hour

$CI > 0.2 \ \& \ CI \leq 0.5$

Mean: 0     STD: 30% of the max PV output of each particular operating hour

$CI > 0.5 \ \& \ CI \leq 0.8$

Mean: 0     STD: 25% of the max PV output of each particular operating hour

CI>0.8

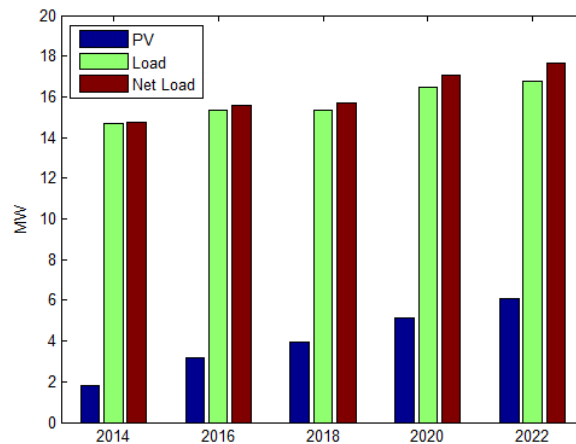
Mean: 0     STD: 10% of the max PV output of each particular operating hour

(The DA PV forecast error generated for each hour is limited to the maximum possible PV output of that operating hour, calculated from historical data/theoretical model.)

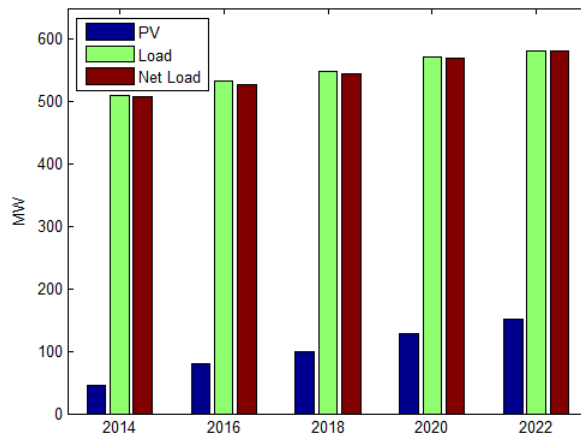
4. Subtract forecast errors (3) from hourly average (1);
5. Add 20 minutes inter-hour ramps to data from (4), mimicking the DA schedule.

## A.6 PV Production Variability

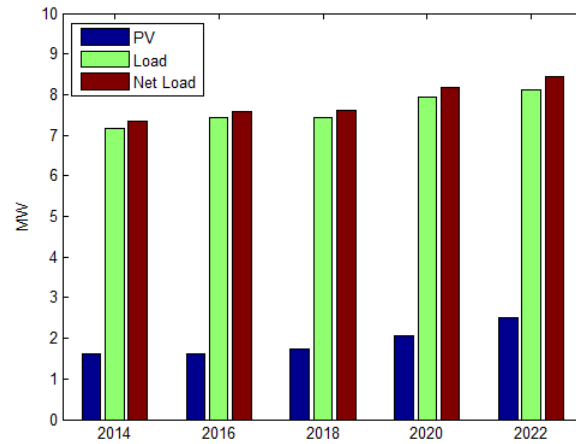
In this section, PV and load variability in different study years are compared using the standard deviation of ramps to illustrate the increase of variability with PV and load growth. Variability within one and 60-minute period for low and high-penetration scenarios are shown as examples in Figure A.10 through Figure A.17. The values of ramp standard deviations for each case are shown in Table A.2 through Table A.5.



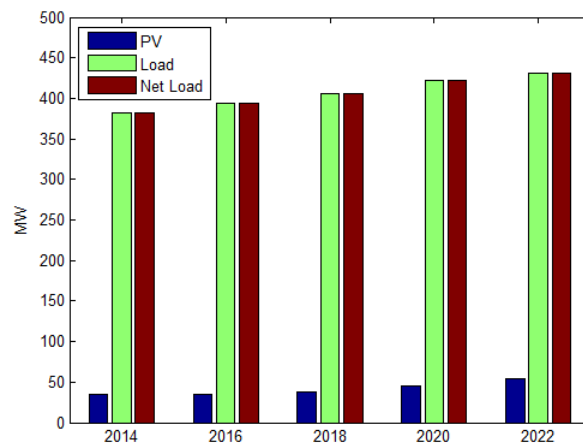
**Figure A.10.** Standard Deviation of PV and Load Ramps – Low Integration Case DEC 1-Minute Interval



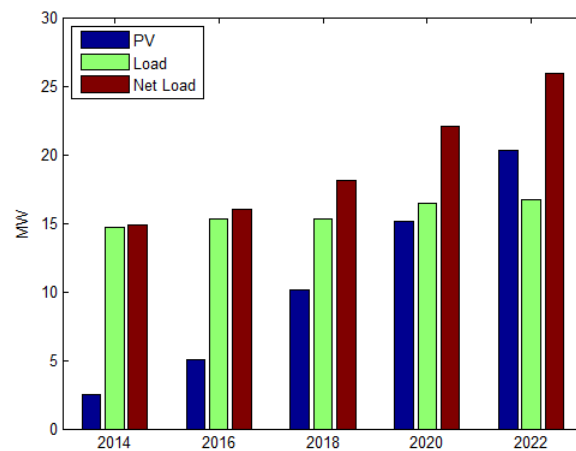
**Figure A.11.** Standard Deviation of PV and Load Ramps – Low-Integration Case DEC 60-Minute Interval



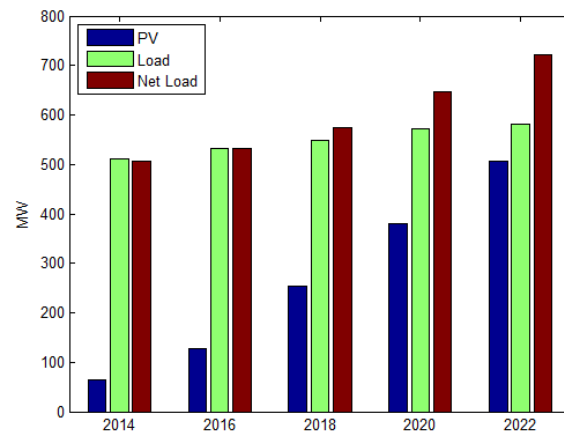
**Figure A.12.** Standard Deviation of PV and Load Ramps – Low-Integration Case DEP 1-Minute Interval



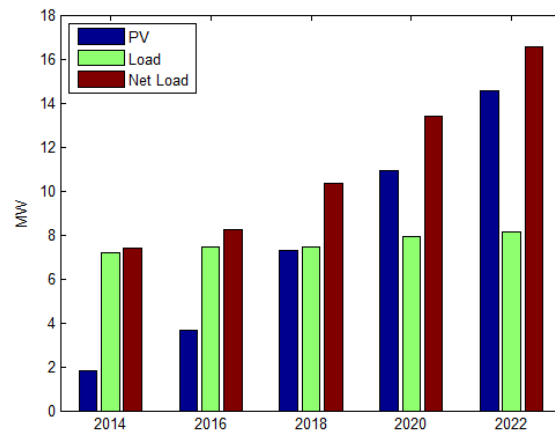
**Figure A.13.** Standard Deviation of PV and Load Ramps – Low-Integration Case DEP 60-Minute Interval



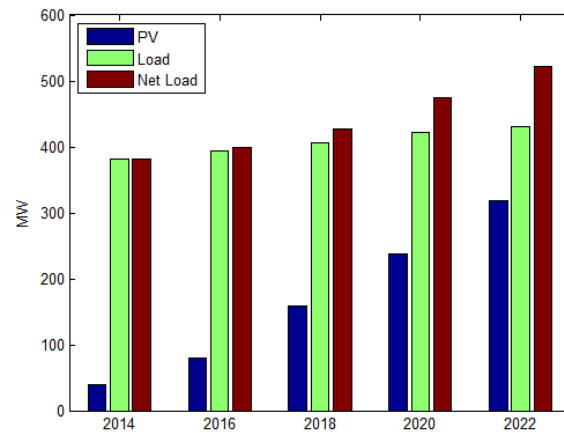
**Figure A.14.** Standard Deviation of PV and Load Ramps – High-Integration Case DEC 1-Minute Interval



**Figure A.15.** Standard Deviation of PV and Load Ramps – High-Integration Case DEC 60-Minute Interval



**Figure A.16.** Standard Deviation of PV and Load Ramps – High-Integration Case DEP 1-Minute Interval



**Figure A.17.** Standard Deviation of PV and Load Ramps – High-Integration Case DEP 60-Minute Interval

**Table A.2.** Standard Deviation of PV and Load Ramps – 1-Minute Time Interval Integration Case

Area	Penetration	PV/Load/Net	2014	2016	2018	2020	2022
DEC	Low	PV	1.83	3.19	3.97	5.11	6.06
		Load	14.71	15.34	15.33	16.47	16.75
		Netload	14.77	15.57	15.71	17.09	17.63
DEP	Low	PV	1.62	1.62	1.74	2.05	2.52
		Load	7.17	7.42	7.45	7.94	8.11
		Netload	7.33	7.57	7.62	8.17	8.45
DEC	Mid	PV	2.18	4.13	7.04	10.13	13.16
		Load	14.71	15.34	15.33	16.47	16.75
		Netload	14.81	15.76	16.66	19.07	20.97
DEP	Mid	PV	1.72	2.63	4.51	6.49	8.55
		Load	7.17	7.42	7.45	7.94	8.11
		Netload	7.35	7.83	8.64	10.17	11.68
DEC	High	PV	2.53	5.06	10.11	15.15	20.26
		Load	14.71	15.34	15.33	16.47	16.75
		Netload	14.85	16.00	18.09	22.03	25.88
DEP	High	PV	1.82	3.64	7.29	10.92	14.57
		Load	7.17	7.42	7.45	7.94	8.11
		Netload	7.37	8.21	10.33	13.40	16.55

**Table A.3.** Standard Deviation of PV and Load Ramps – 5-Minutre Time Interval Integration Case

Area	Penetration	PV/Load/Net	2014	2016	2018	2020	2022
DEC	Low	PV	5.47	9.57	11.90	15.33	18.15
		Load	48.79	50.86	51.75	54.63	55.49
		Netload	48.67	51.00	52.15	55.57	56.99
DEP	Low	PV	4.42	4.42	4.73	5.60	6.85
		Load	34.73	35.92	36.80	38.44	39.26
		Netload	34.87	36.05	36.95	38.67	39.63
DEC	Mid	PV	6.52	12.36	21.09	30.38	39.40
		Load	48.79	50.86	51.75	54.63	55.49
		Netload	48.71	51.38	54.28	60.40	65.44
DEP	Mid	PV	4.69	7.17	12.29	17.68	23.26
		Load	34.73	35.92	36.80	38.44	39.26
		Netload	34.90	36.40	38.41	41.82	44.97
DEC	High	PV	7.57	15.16	30.29	45.43	60.65
		Load	48.79	50.86	51.75	54.63	55.49
		Netload	48.78	51.91	57.81	68.27	78.87
DEP	High	PV	4.96	9.92	19.84	29.76	39.68
		Load	34.73	35.92	36.80	38.44	39.26
		Netload	34.93	36.96	41.23	47.89	54.90

**Table A.4.** Standard Deviation of PV and Load Ramps – 10-Minute Time Interval Integration Case

Area	Penetration	PV/Load/Net	2014	2016	2018	2020	2022
DEC	Low	PV	9.36	16.38	20.36	26.25	31.05
		Load	91.97	95.85	98.15	102.97	104.59
		Netload	91.53	95.66	98.25	103.79	106.12
DEP	Low	PV	7.37	7.37	7.89	9.35	11.43
		Load	68.51	70.85	72.79	75.83	77.44
		Netload	68.63	70.96	72.90	76.06	77.83
DEC	Mid	PV	11.16	21.16	36.10	52.02	67.40
		Load	91.97	95.85	98.15	102.97	104.59
		Netload	91.56	96.13	101.17	110.81	118.71
DEP	Mid	PV	7.83	11.97	20.50	29.51	38.82
		Load	68.51	70.85	72.79	75.83	77.44
		Netload	68.66	71.41	74.84	80.36	85.25
DEC	High	PV	12.96	25.94	51.85	77.79	103.75
		Load	91.97	95.85	98.15	102.97	104.59
		Netload	91.62	96.83	106.37	122.94	139.87
DEP	High	PV	8.28	16.56	33.11	49.68	66.21
		Load	68.51	70.85	72.79	75.83	77.44
		Netload	68.69	72.15	78.77	89.12	99.88

**Table A.5.** Standard Deviation of PV and Load Ramps – 30-Minute Time Interval Integration Case

Area	Penetration	PV/Load/Net	2014	2016	2018	2020	2022
DEC	Low	PV	24.13	42.18	52.47	67.68	79.93
		Load	263.41	274.54	282.59	294.93	299.55
		Netload	261.68	272.81	281.22	294.86	300.71
DEP	Low	PV	18.61	18.62	19.92	23.60	28.84
		Load	197.38	204.11	210.07	218.48	223.08
		Netload	197.38	204.07	210.04	218.68	223.52
DEC	Mid	PV	28.77	54.50	93.04	134.12	173.52
		Load	263.41	274.54	282.59	294.93	299.55
		Netload	261.60	273.54	286.82	309.53	327.83
DEP	Mid	PV	19.75	30.21	51.74	74.51	97.94
		Load	197.38	204.11	210.07	218.48	223.08
		Netload	197.44	204.91	213.87	227.60	239.17
DEC	High	PV	33.41	66.82	133.61	200.57	267.11
		Load	263.41	274.54	282.59	294.93	299.55
		Netload	261.61	274.81	297.89	336.91	376.89
DEP	High	PV	20.89	41.80	83.55	125.42	167.05
		Load	197.38	204.11	210.07	218.48	223.08
		Netload	197.50	206.39	222.23	246.92	272.02

A.7 Reserve Requirements Data

Table A.6. DEC DA Planning Reserve Requirements

Reserve Up		Operating Hour																							
Year	Penetration	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
2014	Low	409	310	310	302	391	473	506	488	466	473	457	492	543	559	596	652	668	698	592	506	513	531	471	413
2014	Mid	401	310	300	303	382	476	495	488	464	461	467	481	546	550	599	633	671	714	582	496	538	543	469	423
2014	High	399	305	306	295	393	466	505	497	465	469	467	464	543	562	613	650	673	708	597	509	530	539	470	413
2016	Low	419	331	322	327	416	497	535	520	488	493	508	516	586	584	653	694	703	723	603	530	554	563	498	432
2016	Mid	421	318	317	337	419	500	526	522	496	512	522	516	573	606	647	694	710	738	616	530	538	554	484	428
2016	High	427	328	316	320	407	492	518	520	499	524	539	548	582	627	702	710	710	718	607	523	558	554	492	428
2018	Low	446	342	335	338	425	522	537	536	511	520	532	541	611	631	691	714	745	739	645	530	564	592	522	447
2018	Mid	438	345	324	341	434	509	544	544	563	570	605	608	654	693	758	764	752	757	653	558	580	585	513	452
2018	High	449	340	339	341	428	520	555	547	595	629	672	692	706	730	833	782	786	751	632	553	578	590	504	442
2020	Low	459	352	349	352	447	529	575	573	546	558	591	553	637	682	738	738	755	777	656	562	593	599	530	477
2020	Mid	449	364	351	356	441	531	579	564	637	650	719	674	719	819	882	835	782	787	645	573	591	617	533	473
2020	High	451	360	344	362	448	522	574	602	762	823	943	829	868	950	1022	950	883	821	654	568	588	608	529	469
2022	Low	472	377	358	360	457	552	590	575	568	600	613	612	657	702	752	809	812	797	689	586	609	623	544	475
2022	Mid	470	369	367	366	456	553	581	600	707	760	820	790	852	874	971	884	871	807	699	597	610	620	545	472
2022	High	473	371	359	359	462	548	599	647	865	1042	1138	1057	1080	1173	1202	1128	974	826	690	594	609	619	536	489
Reserve Down		Operating Hour																							
Year	Penetration	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
2014	Low	-417	-402	-407	-416	-439	-525	-489	-476	-489	-492	-495	-577	-658	-688	-722	-756	-873	-954	-902	-801	-747	-680	-628	-540
2014	Mid	-425	-403	-408	-413	-442	-516	-488	-475	-493	-484	-490	-576	-700	-700	-722	-782	-875	-974	-940	-809	-717	-654	-624	-529
2014	High	-431	-392	-402	-398	-440	-527	-484	-484	-498	-487	-500	-601	-693	-695	-735	-787	-850	-951	-913	-798	-705	-672	-613	-529
2016	Low	-437	-413	-430	-417	-450	-533	-520	-494	-511	-504	-543	-626	-736	-730	-774	-829	-921	-1023	-957	-867	-766	-715	-648	-554
2016	Mid	-437	-415	-426	-414	-458	-540	-502	-503	-526	-531	-562	-646	-744	-746	-775	-841	-920	-1007	-971	-836	-756	-719	-657	-565
2016	High	-450	-419	-433	-411	-459	-546	-524	-490	-534	-552	-596	-662	-751	-788	-800	-853	-925	-1016	-951	-841	-749	-705	-658	-579
2018	Low	-470	-420	-443	-441	-481	-572	-533	-533	-545	-545	-578	-656	-780	-773	-803	-862	-955	-1044	-1010	-888	-794	-738	-674	-595
2018	Mid	-458	-429	-441	-460	-475	-557	-529	-521	-564	-616	-690	-747	-825	-877	-855	-918	-980	-1040	-987	-870	-794	-718	-661	-586
2018	High	-472	-420	-441	-441	-480	-565	-520	-547	-622	-722	-795	-804	-863	-967	-970	-956	-979	-1056	-985	-898	-791	-729	-673	-585
2020	Low	-484	-450	-458	-458	-500	-582	-565	-545	-578	-598	-608	-717	-815	-824	-840	-929	-978	-1069	-1024	-919	-854	-758	-702	-600
2020	Mid	-485	-455	-462	-457	-502	-578	-546	-544	-642	-716	-814	-846	-940	-965	-1019	-1013	-1008	-1107	-999	-884	-801	-772	-706	-615
2020	High	-484	-449	-458	-458	-493	-593	-565	-557	-789	-910	-1060	-1051	-1092	-1217	-1230	-1122	-1110	-1057	-1023	-897	-834	-769	-697	-611
2022	Low	-499	-468	-482	-477	-522	-586	-565	-545	-604	-600	-663	-734	-864	-838	-890	-935	-1008	-1102	-1049	-909	-837	-778	-732	-620
2022	Mid	-493	-453	-483	-473	-501	-594	-556	-557	-728	-865	-1001	-963	-1058	-1081	-1167	-1096	-1085	-1097	-1040	-901	-821	-788	-728	-633
2022	High	-503	-461	-477	-470	-506	-609	-572	-575	-944	-1171	-1360	-1205	-1433	-1451	-1497	-1330	-1218	-1113	-1028	-944	-847	-781	-720	-624

Table A.7. DEP DA Planning Reserve Requirements

Reserve Up		Operating Hour																							
Year	Penetration	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
2014	Low	284	299	307	309	336	409	446	445	469	415	459	466	502	529	583	610	642	647	581	527	462	433	433	437
2014	Mid	281	295	300	315	329	399	461	442	468	418	457	488	483	544	576	591	624	661	593	537	455	411	425	426
2014	High	283	297	306	319	335	398	469	450	449	421	460	477	489	546	560	583	658	643	590	522	464	412	427	418
2016	Low	306	321	326	323	360	422	464	460	471	430	478	490	529	564	615	620	666	662	602	561	490	430	449	454
2016	Mid	298	317	326	332	352	417	470	464	481	433	491	496	521	558	602	622	660	671	600	559	472	440	448	442
2016	High	290	321	302	323	356	430	465	440	491	437	485	505	510	584	629	627	658	683	613	549	465	432	442	460
2018	Low	306	324	327	324	373	432	509	471	480	434	497	508	532	570	617	636	702	703	634	586	499	450	460	467
2018	Mid	302	323	337	337	373	438	491	490	521	473	498	518	550	602	650	672	686	694	631	578	496	439	459	457
2018	High	303	319	341	352	359	430	486	491	536	517	547	579	600	635	679	701	714	711	638	574	504	457	458	453
2020	Low	314	331	343	338	372	449	515	504	503	456	493	541	562	594	625	654	689	737	635	596	523	460	481	463
2020	Mid	330	327	355	358	376	456	512	508	549	510	558	569	602	623	679	703	714	742	640	603	508	454	474	481
2020	High	323	324	346	351	380	451	517	528	656	617	642	658	703	713	777	762	796	753	644	597	509	473	480	474
2022	Low	334	346	353	369	387	474	522	506	540	484	540	552	582	622	661	684	724	741	684	611	516	475	485	508
2022	Mid	345	350	358	367	403	458	532	538	614	565	598	615	641	673	731	742	767	763	660	609	536	482	489	505
2022	High	322	351	353	369	389	467	537	571	751	768	758	747	753	813	882	869	842	757	671	619	519	494	483	485
Reserve Down		Operating Hour																							
Year	Penetration	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
2014	Low	-385	-348	-330	-340	-367	-443	-507	-498	-437	-409	-424	-461	-525	-576	-640	-684	-730	-729	-707	-633	-541	-551	-544	-522
2014	Mid	-374	-336	-340	-334	-375	-451	-500	-498	-432	-400	-423	-461	-534	-588	-625	-698	-718	-722	-690	-627	-556	-541	-547	-527
2014	High	-374	-347	-333	-340	-371	-453	-504	-505	-436	-403	-429	-461	-512	-587	-630	-709	-715	-736	-721	-627	-547	-541	-541	-520
2016	Low	-393	-358	-342	-355	-379	-468	-532	-521	-453	-411	-444	-489	-538	-601	-649	-720	-763	-748	-725	-636	-569	-556	-556	-531
2016	Mid	-393	-355	-347	-354	-391	-470	-524	-522	-460	-424	-440	-520	-541	-616	-654	-731	-743	-747	-712	-639	-561	-560	-563	-532
2016	High	-389	-351	-346	-355	-380	-454	-513	-527	-462	-433	-467	-510	-548	-618	-676	-741	-750	-753	-742	-655	-579	-551	-557	-538
2018	Low	-402	-366	-363	-372	-402	-484	-542	-545	-464	-435	-444	-493	-575	-616	-683	-735	-782	-765	-754	-668	-582	-577	-566	-558
2018	Mid	-404	-360	-361	-372	-417	-469	-536	-536	-493	-469	-507	-541	-581	-669	-712	-755	-789	-783	-738	-663	-582	-581	-577	-557
2018	High	-416	-378	-368	-373	-396	-482	-525	-558	-539	-539	-551	-574	-633	-717	-751	-822	-815	-785	-747	-668	-582	-586	-578	-558
2020	Low	-426	-377	-376	-385	-424	-507	-551	-565	-481	-462	-479	-525	-576	-647	-708	-774	-796	-800	-769	-693	-609	-597	-605	-572
2020	Mid	-419	-385	-378	-385	-409	-509	-544	-557	-541	-537	-531	-586	-639	-702	-779	-814	-842	-799	-776	-696	-610	-594	-597	-560
2020	High	-424	-382	-368	-378	-416	-509	-556	-600	-652	-669	-651	-669	-717	-822	-874	-910	-859	-827	-770	-693	-599	-604	-598	-570
2022	Low	-436	-379	-390	-388	-418	-523	-581	-594	-506	-475	-489	-548	-606	-673	-720	-783	-830	-830	-805	-707	-615	-623	-626	-598
2022	Mid	-449	-392	-386	-394	-430	-510	-566	-585	-590	-613	-600	-628	-672	-758	-875	-864	-875	-825	-819	-706	-604	-619	-629	-598
2022	High	-430	-395	-387	-387	-427	-511	-566	-611	-769	-818	-780	-795	-880	-965	-1028	-1032	-959	-859	-797	-710	-617	-611	-628	-597

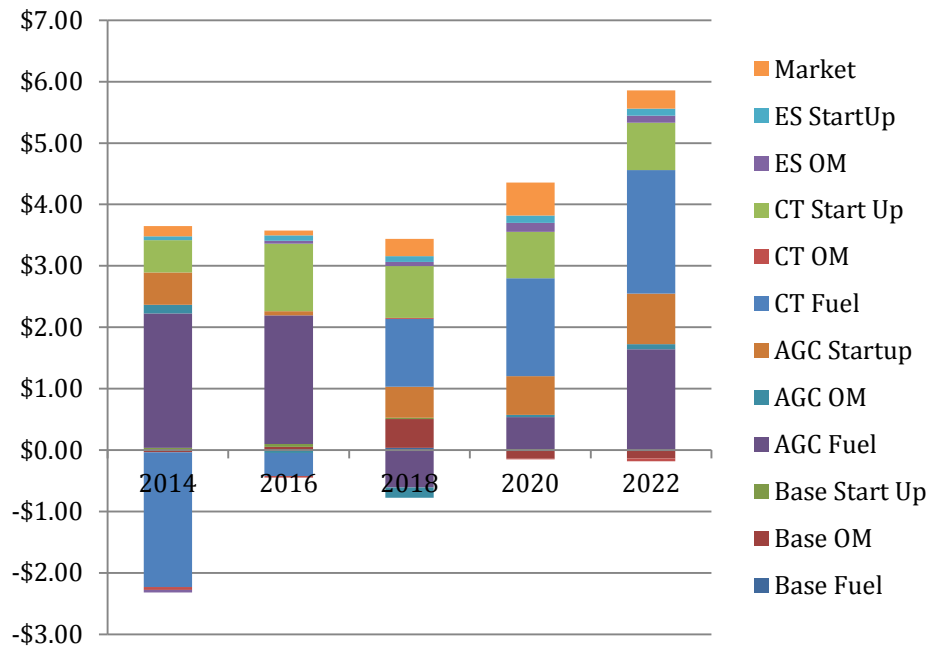
Table A.8. DEC Regulation Reserve Requirements

s		Operating Hour																							
Year	Penetration	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
2014	Low	0	0	0	0	36	134	117	42	29	32	26	18	10	0	0	0	3	59	49	8	0	0	0	0
2014	Mid	0	0	0	0	36	134	117	41	28	31	25	18	11	1	0	0	4	59	49	8	0	0	0	0
2014	High	0	0	0	0	36	134	117	40	27	30	25	18	11	1	0	0	5	59	49	8	0	0	0	0
2016	Low	0	0	0	0	42	144	128	44	27	30	27	20	15	5	0	0	9	64	52	10	0	0	0	0
2016	Mid	0	0	0	0	42	144	128	42	24	28	26	22	17	8	1	0	13	64	52	10	0	0	0	0
2016	High	0	0	0	0	42	144	128	40	22	26	25	22	19	14	4	2	17	65	52	10	0	0	0	0
2018	Low	0	0	0	0	50	154	131	49	30	34	29	23	18	9	1	0	14	69	57	10	0	0	0	0
2018	Mid	0	0	0	0	50	154	131	42	21	28	26	27	29	30	19	23	32	72	57	10	0	0	0	0
2018	High	0	0	0	0	50	154	130	38	13	24	26	36	46	59	54	66	72	79	57	10	0	0	0	0
2020	Low	0	0	0	0	52	163	143	52	31	34	30	28	23	17	7	3	20	74	61	12	0	0	0	0
2020	Mid	0	0	0	0	52	163	142	42	18	27	28	39	48	60	55	67	74	83	61	12	0	0	0	0
2020	High	0	0	0	0	52	163	141	36	8	25	32	60	91	127	126	144	148	103	61	12	0	0	0	0
2022	Low	0	0	0	0	55	166	149	51	27	32	30	30	28	26	14	12	26	75	61	13	0	0	0	0
2022	Mid	0	0	0	0	55	166	148	41	11	24	32	51	70	101	99	114	120	93	61	13	0	0	0	0
2022	High	0	0	0	0	55	166	147	33	4	28	41	91	140	202	202	223	230	135	61	13	0	0	0	0
Reserve Down		Operating Hour																							
Year	Penetration	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
2014	Low	-9	-1	0	0	0	0	0	0	-25	-25	-14	-6	-1	0	0	-2	-3	-12	-17	-9	-51	-86	-84	-52
2014	Mid	-9	-1	0	0	0	0	0	0	-28	-26	-15	-7	-1	0	0	-2	-3	-12	-17	-9	-51	-86	-84	-52
2014	High	-9	-1	0	0	0	0	0	0	-30	-28	-15	-7	-2	0	0	-2	-3	-11	-17	-9	-51	-86	-84	-52
2016	Low	-11	-1	0	0	0	0	0	-1	-38	-33	-19	-9	-4	0	0	-2	-3	-13	-20	-12	-56	-94	-92	-60
2016	Mid	-11	-1	0	0	0	0	0	-2	-46	-37	-22	-11	-6	0	0	-2	-3	-12	-20	-11	-56	-94	-92	-60
2016	High	-11	-1	0	0	0	0	0	-4	-55	-42	-25	-13	-8	-1	0	-1	-2	-11	-19	-11	-56	-94	-92	-60
2018	Low	-14	-2	0	0	0	0	0	-3	-44	-38	-23	-12	-6	0	0	-2	-4	-13	-21	-13	-60	-100	-98	-64
2018	Mid	-14	-2	0	0	0	0	0	-11	-69	-54	-39	-22	-14	-3	0	-1	-2	-10	-20	-13	-60	-100	-98	-64
2018	High	-14	-2	0	0	0	0	0	-22	-97	-76	-62	-42	-28	-11	0	0	-2	-9	-19	-12	-60	-100	-98	-64
2020	Low	-17	-3	0	0	0	0	0	-7	-59	-47	-30	-17	-9	-1	0	-2	-4	-15	-23	-16	-65	-109	-107	-71
2020	Mid	-17	-3	0	0	0	0	0	-23	-104	-80	-64	-43	-29	-12	0	-1	-2	-11	-21	-15	-65	-109	-107	-71
2020	High	-17	-3	0	0	0	0	0	-47	-161	-125	-111	-85	-64	-31	-6	0	-2	-9	-20	-14	-65	-109	-107	-71
2022	Low	-19	-3	0	0	0	0	0	-11	-70	-53	-35	-19	-14	-2	0	-2	-4	-16	-26	-16	-67	-112	-110	-75
2022	Mid	-19	-3	0	0	0	0	0	-35	-140	-108	-89	-69	-51	-20	-1	0	-2	-12	-23	-15	-67	-112	-110	-75
2022	High	-19	-3	0	0	0	0	0	-81	-232	-182	-172	-142	-116	-56	-27	-4	-1	-8	-20	-14	-67	-112	-110	-75

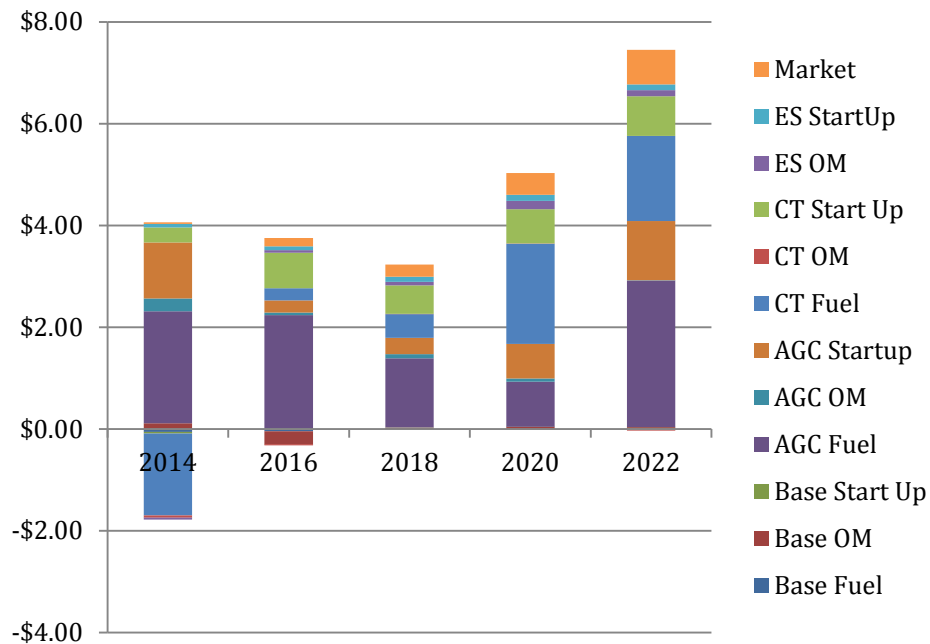
Table A.9. DEP Regulation Reserve Requirements

Reserve Up		Operating Hour																							
Year	Penetration	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
2014	Low	0	0	0	0	4	55	107	17	23	22	24	18	13	7	1	0	10	45	32	15	5	0	0	0
2014	Mid	0	0	0	0	4	55	107	16	23	22	24	18	13	8	1	0	10	45	32	15	5	0	0	0
2014	High	0	0	0	0	4	55	107	16	22	22	24	18	13	8	1	0	10	45	32	15	5	0	0	0
2016	Low	0	0	0	0	5	60	114	19	26	23	26	21	15	9	2	0	11	48	33	16	5	0	0	0
2016	Mid	0	0	0	0	5	59	114	17	23	21	25	21	16	11	4	1	13	48	33	16	5	0	0	0
2016	High	0	0	0	0	5	59	113	15	20	19	24	23	18	14	7	4	20	49	33	16	5	0	0	0
2018	Low	0	0	0	0	6	63	121	22	30	27	29	23	16	11	2	0	13	50	39	18	6	0	0	0
2018	Mid	0	0	0	0	6	63	119	16	21	22	28	25	22	17	12	12	30	52	39	18	6	0	0	0
2018	High	0	0	0	0	6	63	118	14	16	20	30	31	32	30	29	44	66	60	39	18	6	0	0	0
2020	Low	0	0	0	0	8	69	127	25	32	28	31	24	19	13	4	1	14	53	39	19	6	0	0	0
2020	Mid	0	0	0	0	8	69	125	17	19	22	29	31	30	28	25	35	57	60	39	19	6	0	0	0
2020	High	0	0	0	0	8	68	123	15	13	20	33	46	52	58	66	91	121	84	39	19	6	0	0	0
2022	Low	0	0	0	0	9	73	132	26	32	28	32	27	21	15	6	2	17	59	37	20	7	0	0	0
2022	Mid	0	0	0	0	9	72	129	18	18	21	32	40	38	41	41	60	87	75	37	20	7	0	0	0
2022	High	0	0	0	0	9	71	127	16	9	24	40	63	79	96	108	138	176	116	37	20	7	0	0	0
Reserve Down		Operating Hour																							
Year	Penetration	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
2014	Low	-21	-5	-1	0	0	0	0	-10	-32	-32	-18	-8	-2	0	0	0	-2	-2	-7	-9	-6	-41	-63	-50
2014	Mid	-21	-5	-1	0	0	0	0	-10	-32	-33	-19	-8	-2	0	0	0	-2	-2	-7	-9	-6	-41	-63	-50
2014	High	-21	-5	-1	0	0	0	0	-10	-33	-33	-19	-9	-2	0	0	0	-2	-2	-7	-9	-6	-41	-63	-50
2016	Low	-24	-6	-1	0	0	0	0	-11	-34	-34	-20	-10	-3	-1	0	0	-2	-3	-8	-11	-8	-45	-66	-55
2016	Mid	-24	-6	-1	0	0	0	0	-15	-40	-38	-23	-11	-4	0	0	0	-2	-2	-8	-10	-8	-45	-66	-55
2016	High	-24	-6	-1	0	0	0	0	-19	-47	-43	-26	-12	-5	-1	0	0	-2	-2	-8	-10	-8	-45	-66	-55
2018	Low	-27	-7	-1	0	0	0	0	-12	-35	-34	-22	-11	-4	-1	0	-1	-4	-2	-9	-13	-9	-48	-71	-59
2018	Mid	-27	-7	-1	0	0	0	0	-25	-54	-45	-29	-15	-7	-1	0	0	-3	-2	-8	-12	-9	-48	-71	-59
2018	High	-27	-7	-1	0	0	0	0	-43	-76	-57	-37	-23	-13	-2	-2	0	-3	-2	-7	-12	-9	-48	-71	-59
2020	Low	-30	-8	-2	0	0	0	0	-16	-41	-41	-26	-12	-6	-2	0	0	-3	-4	-11	-14	-11	-54	-78	-64
2020	Mid	-30	-8	-2	0	0	0	0	-39	-74	-61	-38	-22	-11	-2	-1	0	-3	-3	-10	-14	-11	-54	-78	-64
2020	High	-30	-8	-2	0	0	0	0	-76	-118	-84	-54	-39	-30	-11	-9	0	-2	-2	-9	-14	-11	-54	-78	-64
2022	Low	-32	-10	-2	0	0	0	0	-20	-45	-44	-28	-14	-6	-2	0	0	-4	-4	-12	-15	-12	-56	-80	-68
2022	Mid	-32	-10	-2	0	0	0	0	-55	-94	-73	-48	-30	-19	-5	-4	0	-3	-3	-10	-14	-12	-56	-80	-68
2022	High	-32	-10	-2	0	0	0	-3	-111	-164	-110	-78	-61	-48	-26	-18	-2	-2	-3	-9	-14	-12	-56	-80	-68

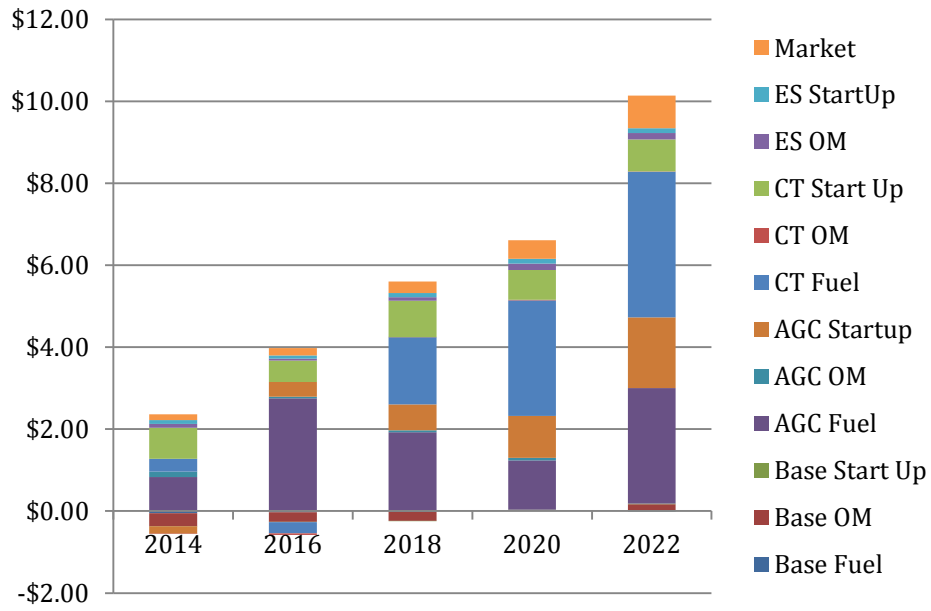
## A.8 PV Integration Cost Breakdown



**Figure A.18.** PV Integration Cost by Component – Compliance Cases



**Figure A.19.** PV Integration Cost by Component – Mid-Penetration Cases



**Figure A.20.** PV Integration Cost by Component – Compliance Case

**Appendix B**  
**Transmission Study**

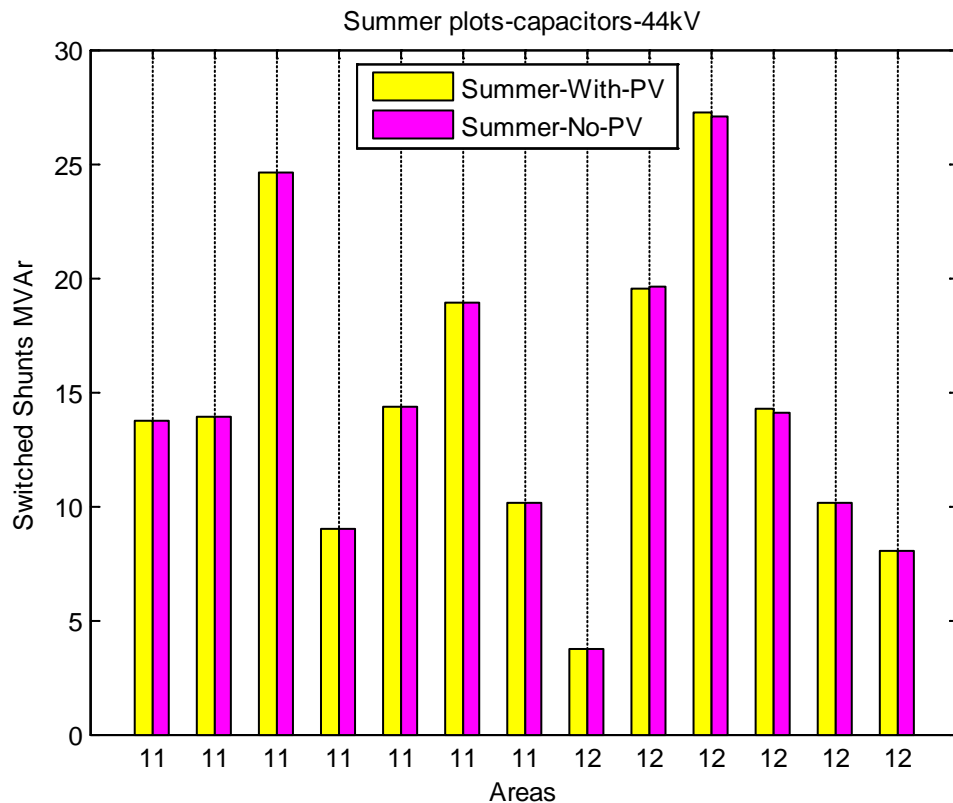
## Appendix B

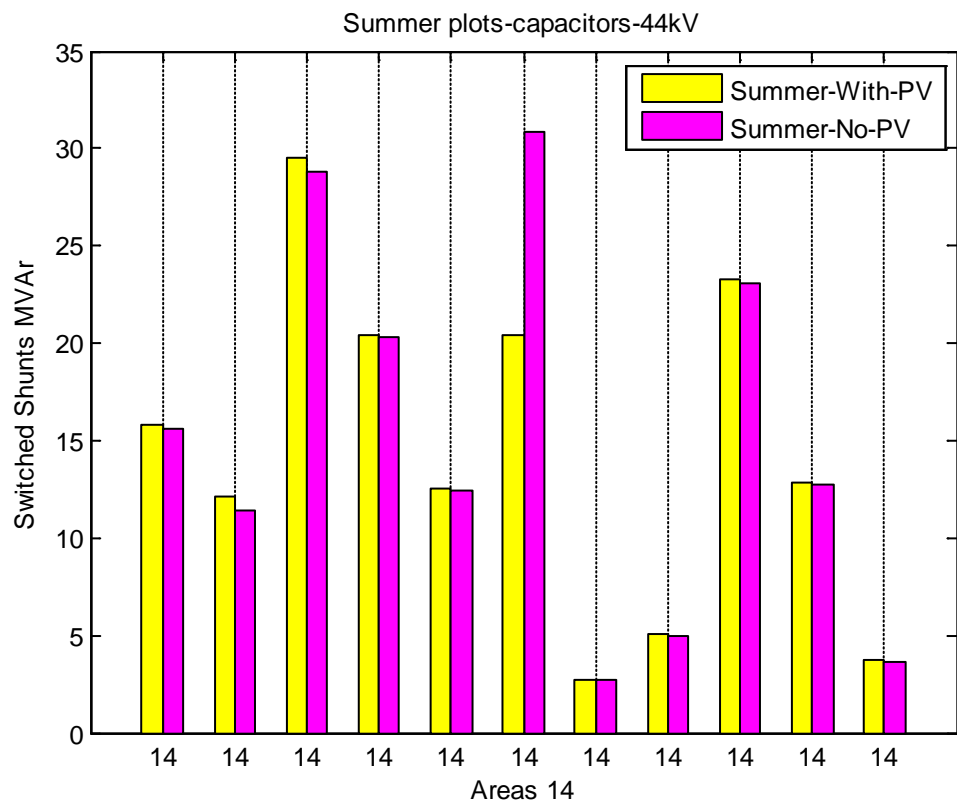
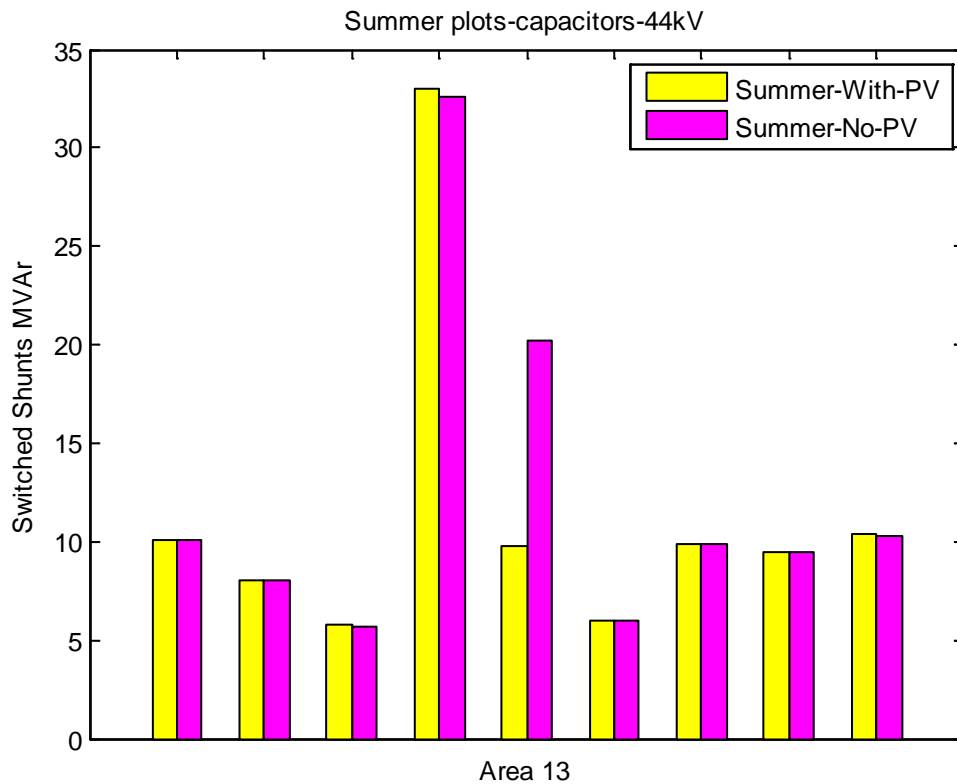
### Transmission Study

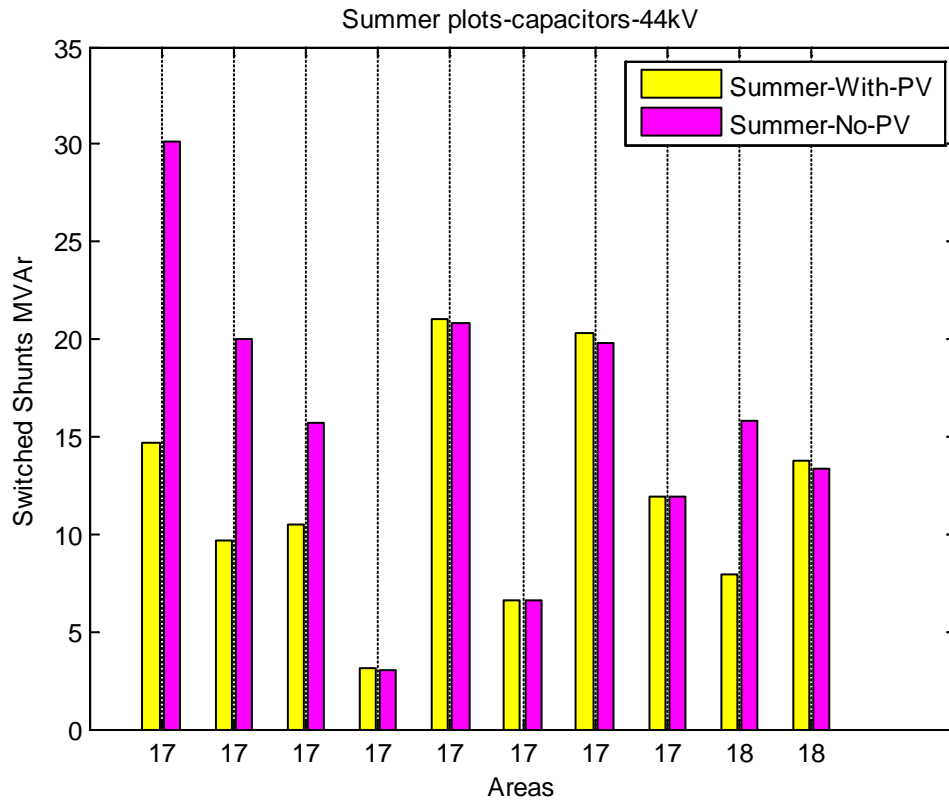
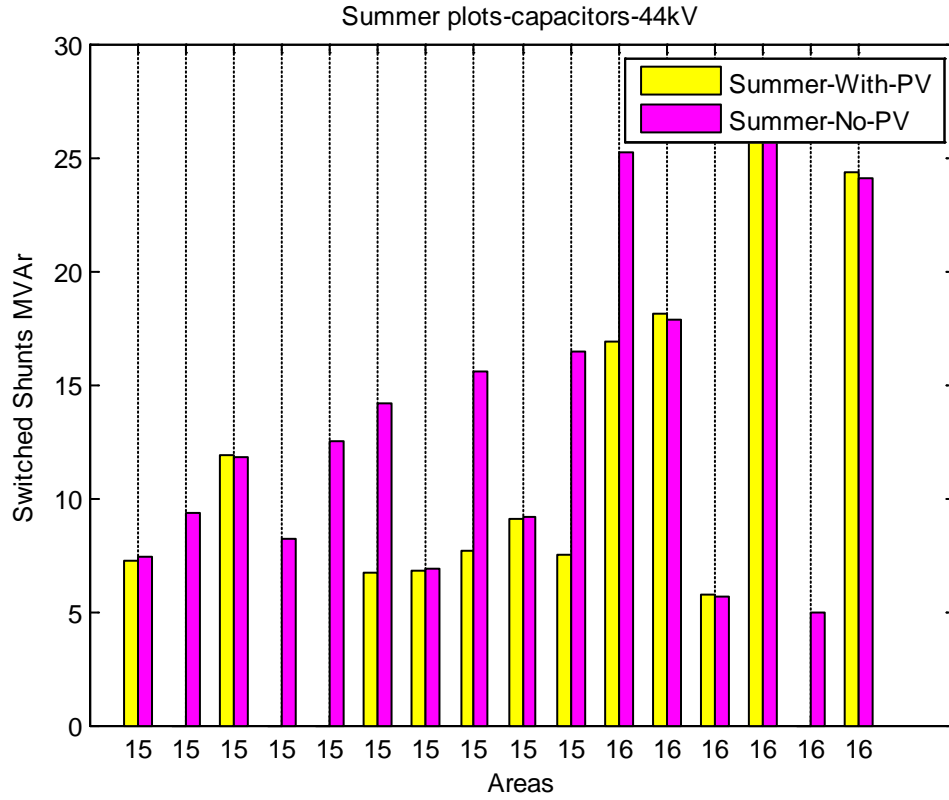
### Switching of Capacitor and Reactor Banks

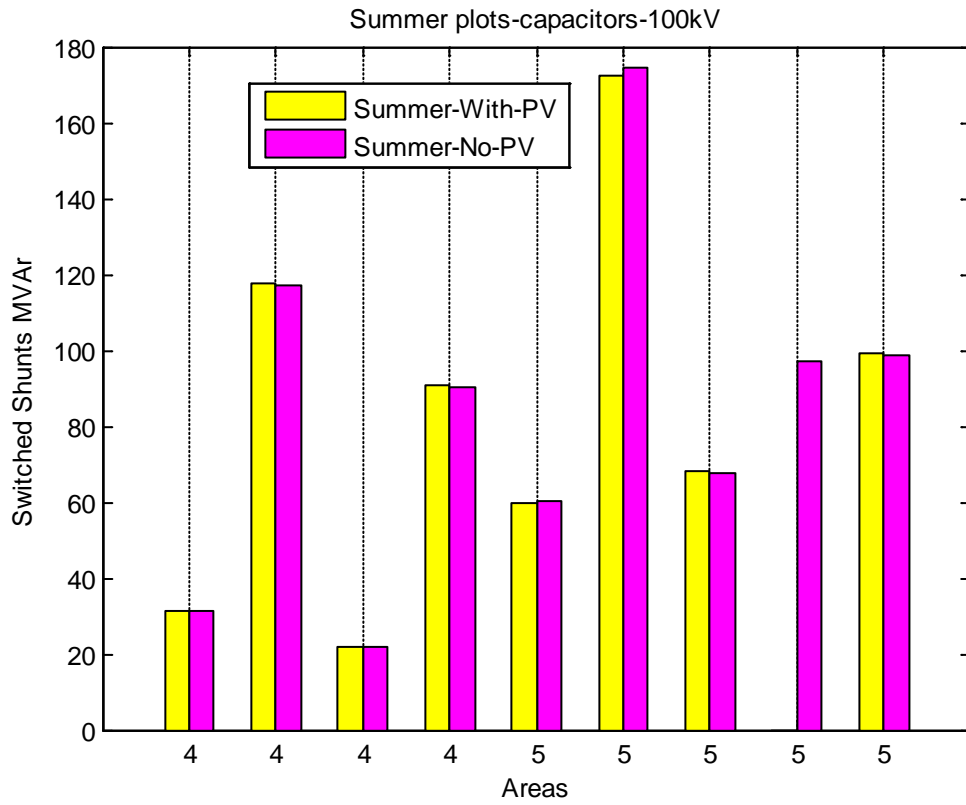
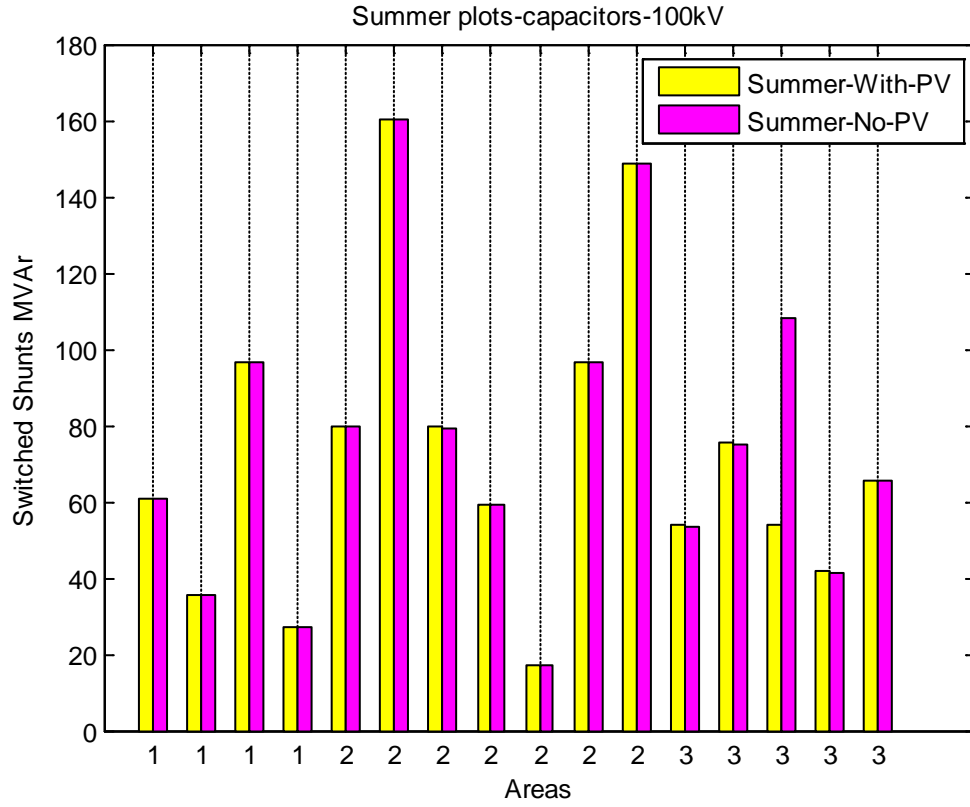
This appendix gives comparisons of capacitor and reactor banks switching for each of four cases analyzed in the transmission study with and without photovoltaic (PV) generation. The switching at different areas of the Duke transmission system is given in the following figures. It should be noted that only capacitor banks that were switched in at least one of the two scenarios (with or without PV) are included.

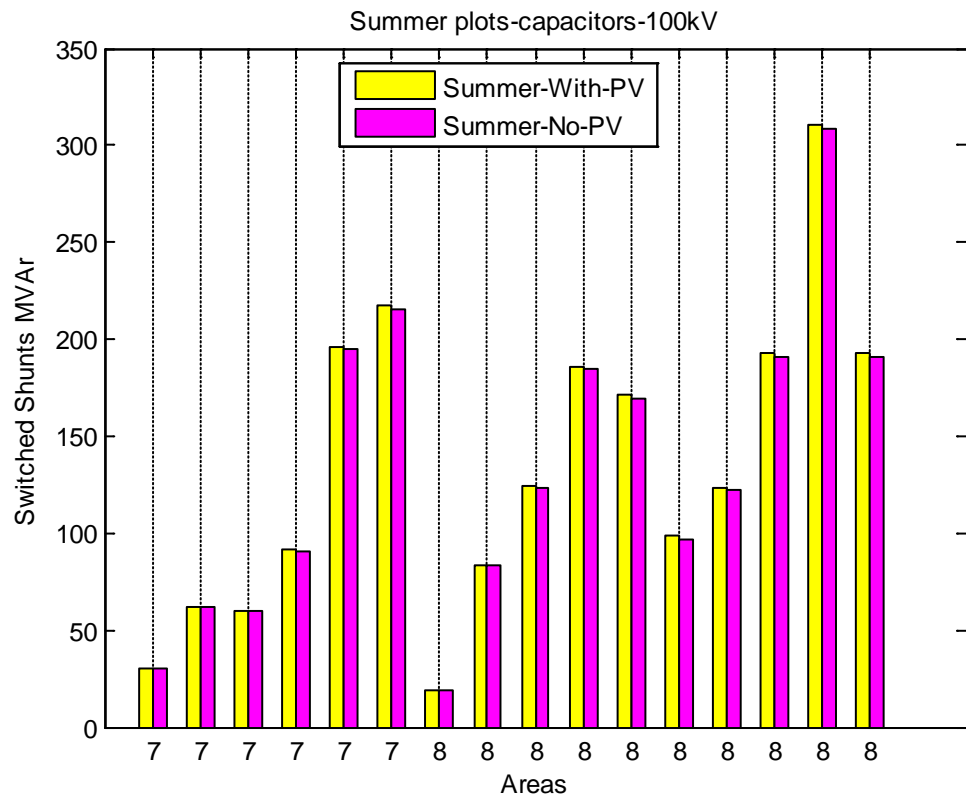
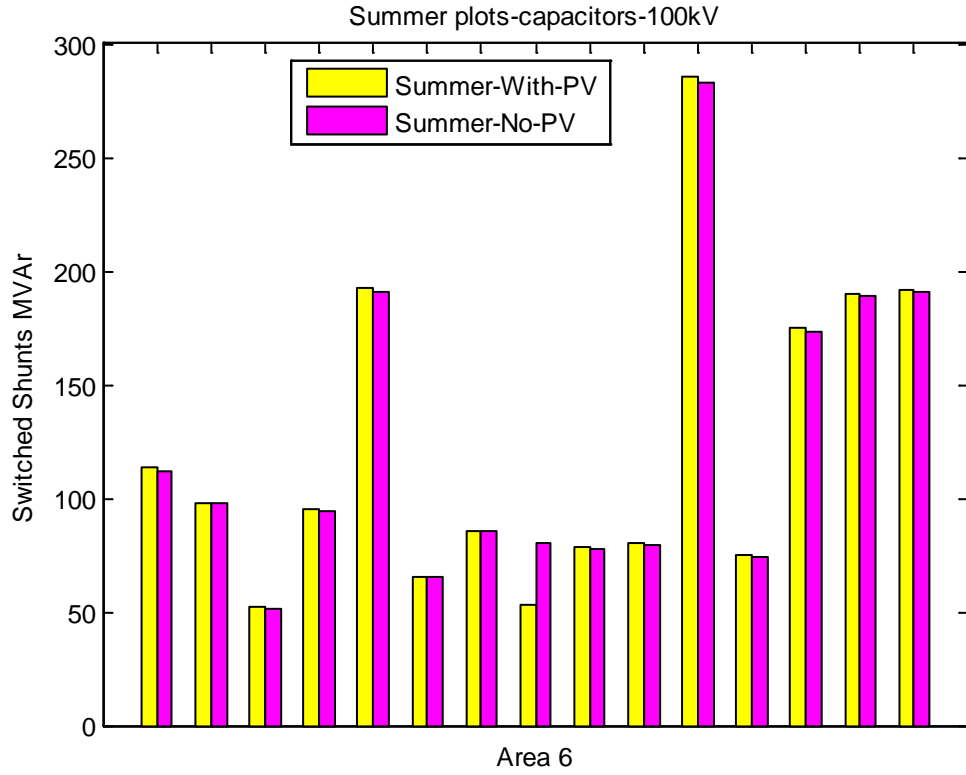
#### B.1 Summer Case-Capacitor Banks Switching







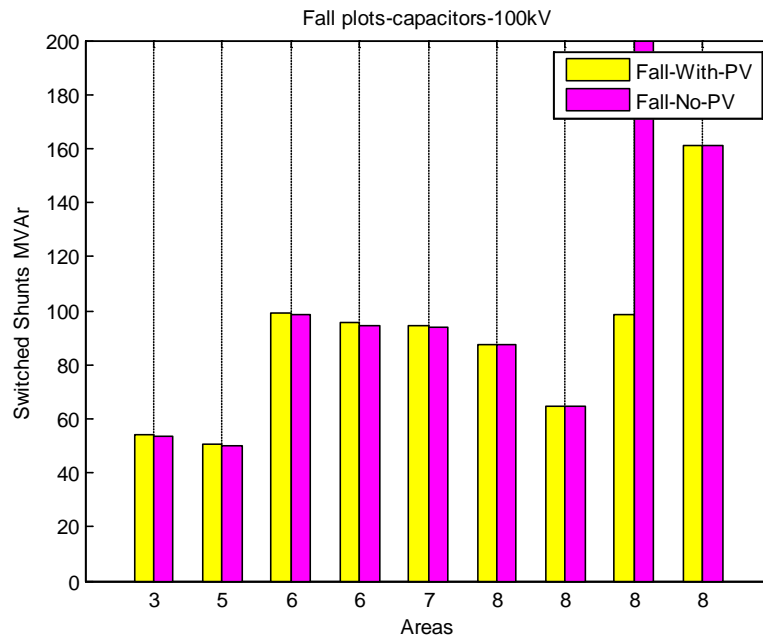
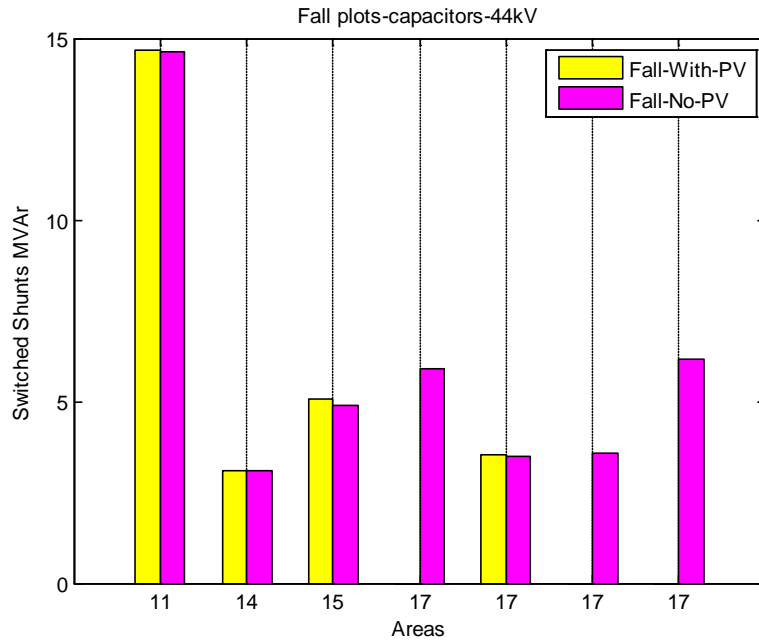




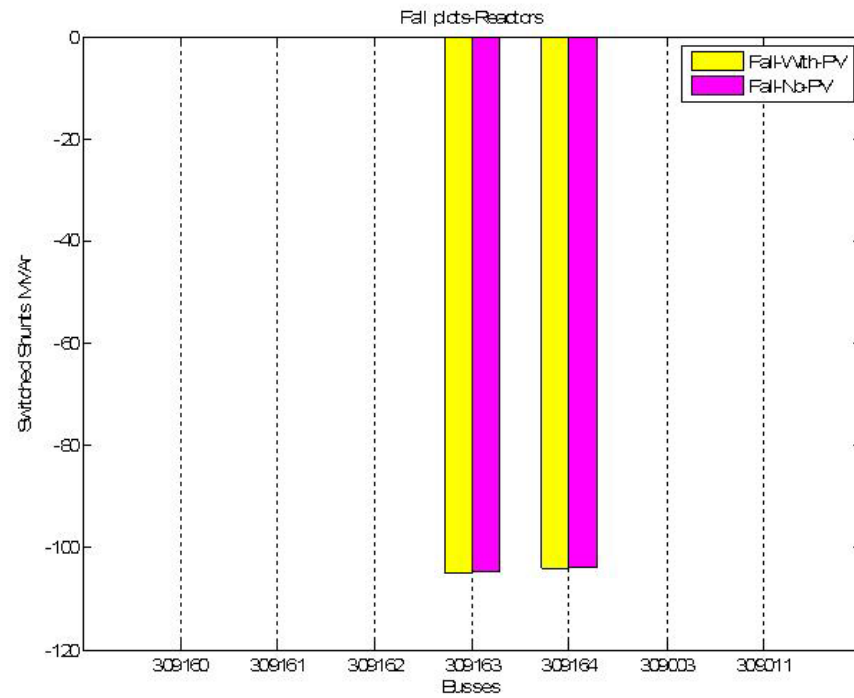
## B.2 Summer Case-Reactor Banks Switching

None of the 7 reactor banks in Duke Energy transmission system were switched on in both the case without PV and the case with PV

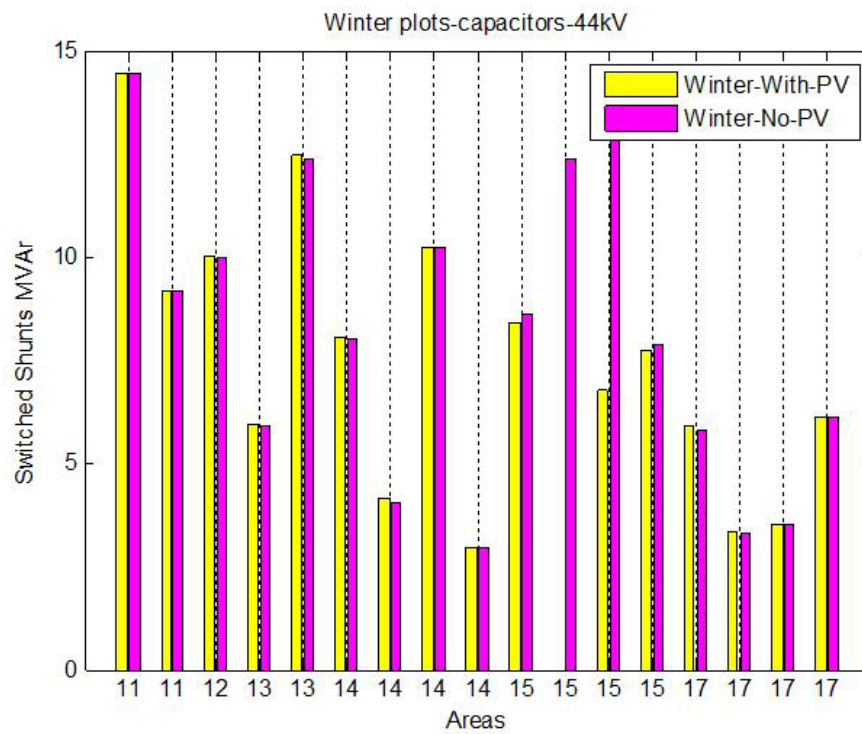
## B.3 Fall Case- Capacitor Banks Switching

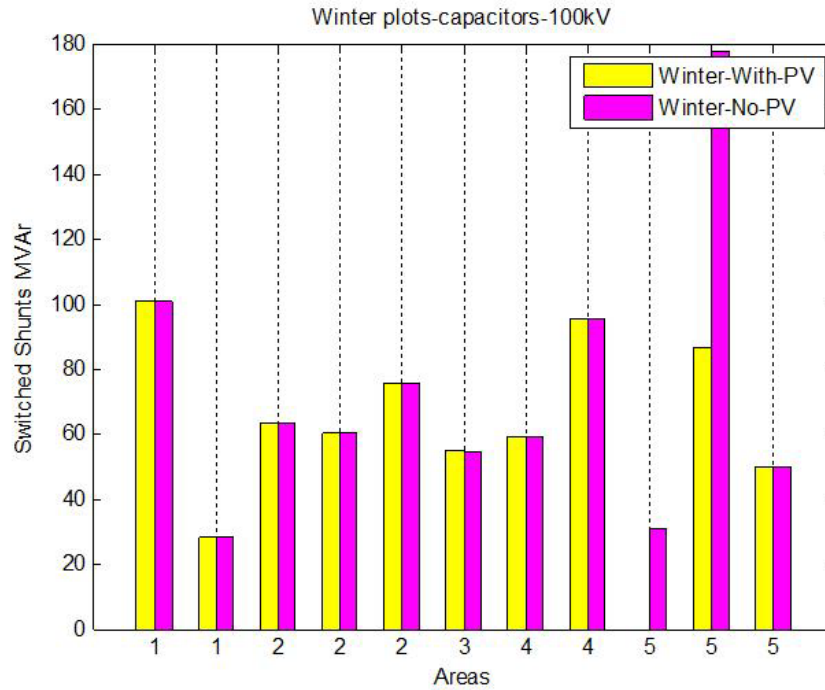


## B.4 Fall Case- Reactors Banks Switching



## B.5 Winter Case – Capacitor Banks Switching

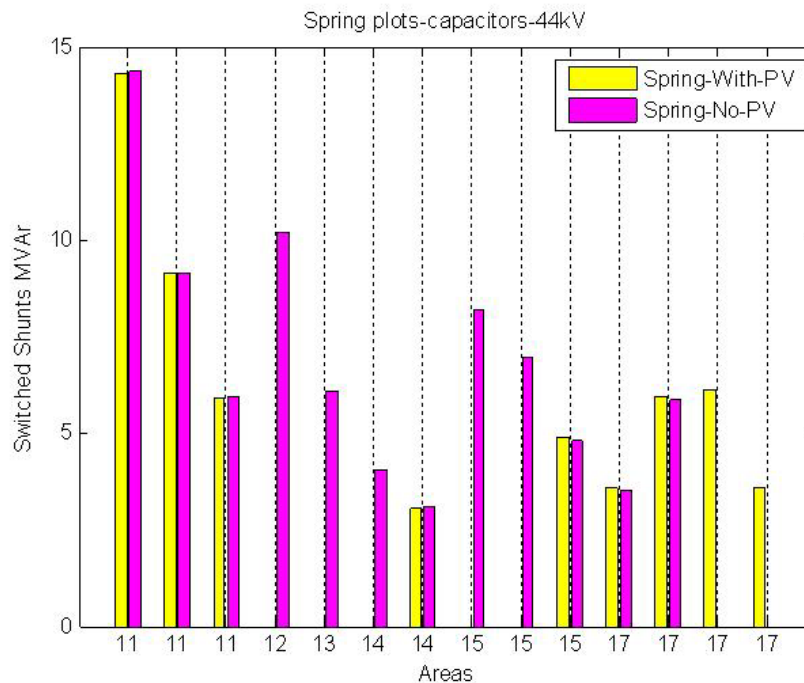




## B.6 Winter Case - Reactor Banks Switching

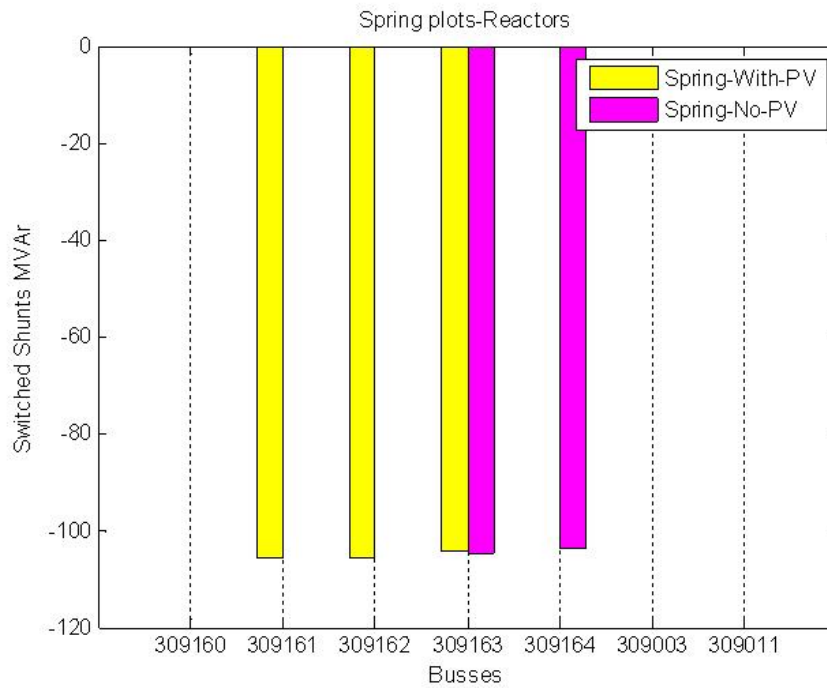
None of the 7 reactor banks in Duke Energy transmission system were switched on in both the case without PV and the case with PV

## B.7 Spring Case - Capacitor Banks Switching





## B.8 Spring Case-Reactor Banks Switching



# **Appendix C**

## **Distribution Study**

## Appendix C

### Distribution Study

The following table shows the PV total (kW) per circuit, the unit kW size, and the number of units.

Circuit	PV Total KW	PV Size (KW)	Number of Units
1	3	3	1
2	14,855	4,952	3
3	14,855	1,486	10
4	6,293	6,293	1
5	48	2	22
6	48	12	4
7	96	96	1
8	5,000	5,000	1
9	5,000	1,000	5
10	392	392	1
11	392	196	2
12	392	4	100
13	1,000	1,000	1
14	13,000	2,600	5
15	5,000	5,000	1
16	410	410	1
17	5,000	5,000	1
18	48	2	22
19	48	48	1
20	48	10	5
21	5,000	5,000	1
22	1,000	1,000	1
23	392	392	1
24	10,000	5,000	2
25	800	800	1
26	5,000	5,000	1
27	48	2	20
28	48	2	30
29	48	48	1
30	48	5	10
31	48	24	2
32	2,500	2,500	1
33	2	2	1
34	4,645	2,322	2

Circuit	PV Total KW	PV Size (KW)	Number of Units
35	2,500	2,500	1
36	2,000	2,000	1
37	4,645	1,161	4
38	5,000	5,000	1
39	3,000	3,000	1
40	3,000	3,000	1
41	1,000	1,000	1
42	1,000	1,000	1
43	410	410	1
44	392	20	20
45	392	8	50
46	392	39	10
47	392	26	15
48	500	10	50
49	500	2	250
50	500	3	200
51	500	50	10
52	50	2	25
53	2,000	2,000	1
54	1,393	116	12
55	3,000	3,000	1
56	13	13	1
57	128	128	1
58	128	26	5
59	400	2	200
60	6,293	6,293	1
61	6,293	6,293	1
62	7,000	7,000	1
63	5,000	5,000	1
64	257	257	1
65	5,000	5,000	1
66	2,500	2,500	1
67	6,293	6,293	1
68	4,000	4,000	1
69	20,000	5,000	4
70	20,500	20,500	1
71	1,000	1,000	1
72	5,000	5,000	1
73	113	113	1
74	1,000	1,000	1
75	48	48	1

Circuit	PV Total KW	PV Size (KW)	Number of Units
76	48	48	1
77	48	2	25
78	410	410	1
79	113	113	1
80	1,000	1,000	1
81	500	10	50
82	2,500	2,500	1
83	410	410	1
84	5,000	5,000	1
85	48	2	25
86	1,000	10	100
87	4,645	4,645	1
88	4,645	2,322	2
89	392	196	2
90	392	392	1
91	392	13	30
92	1,000	1,000	1
93	5,000	5,000	1
94	1,500	1,500	1
95	50	50	1
96	1,000	1,000	1
97	2,112	2,112	1
98	6	3	2
99	3	3	1
100	200	200	1
101	200	2	100
102	392	4	100
103	392	392	1
104	392	6	70
105	2,112	1,056	2
106	2,112	704	3
107	2,112	528	4
108	6293	6293	1
109	48	48	1
110	410	410	1
111	1,500	1,500	1
112	4,500	4,500	1
113	5,000	5,000	1
114	48	2	25
115	48	2	20
116	20	4	5

Circuit	PV Total KW	PV Size (KW)	Number of Units
117	20	4	5
118	20	2	10
119	1,000	1,000	1
120	4,645	1,548	3
121	392	392	1
122	392	392	1
123	3,000	3,000	1
124	5,000	5,000	1
125	2,112	2,112	1
126	2,112	2,112	1
127	3,000	3,000	1
128	500	10	50
129	1,000	10	100
130	500	2	250
131	1,000	2	500
132	5,000	5,000	1
133	3,500	3,500	1
134	48	48	1
135	1,500	1,500	1
136	1,500	1,500	1
137	48	2	22
138	1,393	7	207
139	1,393	93	15
140	4,000	4,000	1
141	8,000	8,000	2
142	200	200	1
143	500	100	5
144	1,000	1,000	1
145	100	2	50
146	48	48	1
147	4,716	2,358	2
148	392	392	1
149	20,000	1,000	20
150	8,000	4,000	2
151	1,393	1,393	1
152	1,393	697	2
153	1,393	464	3
154	128	128	1
155	1,393	464	3
156	1,393	697	2
157	1,500	1,500	1

Circuit	PV Total KW	PV Size (KW)	Number of Units
158	1,393	199	7
159	250	250	1
160	4,000	4,000	1
161	300	3	100
162	250	250	1
163	3,000	3,000	1
164	3,000	3,000	3
165	500	10	50
166	450	450	1
167	500	500	1
168	2	2	1
169	5,000	1,000	5
170	6,293	6,293	1
171	2,112	211	10
172	2,112	422	5
173	392	78	5
174	5,000	5,000	1
175	6	6	1
176	392	131	3
177	392	39	10
178	392	392	1
179	250	25	10
180	1,393	199	7
181	3,000	3,000	1
182	3,000	1,500	2
183	500	500	1
184	3,000	1,500	2
185	500	5	100
186	5,000	5,000	1
187	1,000	1,000	1
188	5000	5000	1
189	500	10	50
190	100	100	1
191	50	50	1
192	2,787	2,787	1
193	1393	107	13
194	48	24	2
195	48	2	22
196	250	13	20
197	9	9	1
198	700	700	1

Circuit	PV Total KW	PV Size (KW)	Number of Units
199	3,000	1,000	3
200	500	500	1
201	500	10	50
202	1,000	10	100
203	500	500	1
204	5,000	2,500	2
205	100	100	1
206	500	250	2
207	2,112	2,112	1
208	48	48	1
209	48	48	1
210	48	48	1
211	48	48	1
212	3,000	1,000	3
213	2,000	2,000	1
214	128	128	1
215	2,500	2,500	1
216	2	2	1
217	800	800	1
218	1,000	1,000	1
219	48	48	1
220	48	3	15
221	48	2	22
222	48	48	1
223	29	3	10
224	425	43	10
225	400	400	1
226	5,000	5,000	1
227	48	3	15
228	48	2	22
229	48	2	30
230	6	6	1
231	5,000	5,000	1
232	10,000	10,000	2
233	5,000	5,000	1
234	2,000	2,000	1
235	1393	40	35
236	1393	30	46
237	100	100	1
238	100	100	1
239	3,000	1,000	3

Circuit	PV Total KW	PV Size (KW)	Number of Units
240	3,000	1,00	30
241	1,000	1,000	1
242	600	600	1
243	48	48	1
244	48	48	1
245	14,855	2,971	5
246	5,000	5,000	1
247	14,855	4,952	3
248	14,855	1,486	10
249	3,000	3,000	1
250	2,000	100	20
251	3,000	1,000	3
252	48	48	1
253	48	5	10
254	48	24	2
255	7,000	7,000	2
256	15,000	15,000	3
257	2,500	2,500	1
258	48	5	10
259	1,000	1000	1
260	1,000	1,000	1
261	5,000	5,000	1
262	6,293	6,293	1
263	6,293	6,293	1
264	3,000	3,000	1
265	6,293	6,293	1
266	6,293	2,098	3
267	81	81	1
268	2,112	1,056	2
269	6,293	6,293	1
270	1,393	34	41
271	392	78	5
272	48	48	1
273	5,000	2,500	2
274	5,000	5,000	1
275	5,000	5,000	1
276	4,645	4,645	1
277	5,000	5,000	1
278	6,000	6,000	1
279	4,000	4,000	1
280	4,000	4,000	1

Circuit	PV Total KW	PV Size (KW)	Number of Units
281	5,000	5,000	1
282	20,000	4,000	5
283	20,000	5,000	4
284	20,000	10,000	2
285	20,000	4,000	5
286	1,393	50	28
287	1,393	20	71
288	4,000	4,000	1
289	4,000	4,000	1
290	2,000	2,000	1
291	250	250	1
292	392	392	1
293	392	196	2
294	6,293	1,049	6
295	6,293	6,293	1
296	5,000	5,000	1
297	6,293	6,293	1
298	1,000	2	500
299	4,645	929	5
300	5,000	5,000	1
301	4,645	4,645	1
302	4,645	4,645	1
303	5,000	5,000	1
304	5,000	5,000	1
305	6	6	1
306	1,500	1,500	1
307	126	126	1
308	2,000	2,000	1
309	5,000	5,000	1
310	6,293	6,293	1
311	48	24	2
312	48	12	4
313	48	5	10
314	96	2	60
315	3,000	3,000	1
316	3,000	3,000	1
317	392	392	1
318	392	20	20
319	392	8	50
320	11	3	4
321	410	82	5

Circuit	PV Total KW	PV Size (KW)	Number of Units
322	6	3	2
323	48	48	1
324	48	48	1
325	48	48	1
326	128	128	1
327	10	5	2
328	10	2	5
329	500	500	1
330	500	10	50
331	250	50	5
332	3,000	3,000	1
333	100	100	1
334	1,600	1,600	1
335	48	48	1
336	48	10	5
337	48	5	10
338	48	2	22
339	48	5	9
340	48	48	1
341	5,000	5,000	1
342	10,000	10,000	2
343	48	48	1
344	392	392	1
345	392	392	1
346	392	392	1
347	5,000	5,000	1
348	15,000	15,000	3
349	9,000	3,000	3
350	3,500	3,500	1
351	1,306	1,306	1
352	1,306	326	4
353	1,306	653	2
354	410	4	100
355	12585	6,293	2
356	6,293	6,293	1
357	410	410	1
358	4,000	4,000	1
359	29	29	1
360	5,000	5,000	1
361	48	48	1
362	1,000	10	100

Circuit	PV Total KW	PV Size (KW)	Number of Units
363	500	500	1
364	4,716	4,716	1
365	257	257	1
366	500	500	1
367	1,000	10	100
368	1,000	20	50
369	1,000	5	200
370	3,000	3,000	1
371	1,393	1,393	1
372	1,393	348	4
373	1,393	199	7
374	1,393	155	9
375	5,000	5,000	1
376	5,000	5,000	1
377	6,293	6,293	1
378	300	10	30
379	300	300	1
380	200	100	2
381	1,231	410	3
382	1,393	139	10
383	1,393	25	56
384	1,393	28	49
385	5,000	5,000	1
386	1,000	1,000	1
387	1,000	10	100
388	5,000	5,000	1
389	1,000	4	250
390	1,000	1,000	1
391	10,000	2,000	5
392	5,000	5,000	1
393	5,000	5,000	1
394	5,000	5,000	1
395	48	48	1
396	48	48	1
397	48	24	2
398	6,293	3,146	2
399	6,293	6,293	1
400	1,393	1,393	1
401	9,000	4,500	2
402	30,000	1,000	30
403	5,000	5,000	1

Circuit	PV Total KW	PV Size (KW)	Number of Units
404	2,000	1,000	2
405	100	100	1
406	2	2	1
407	2	2	1
408	6,293	6,293	1
409	6,293	2,098	3
410	6,293	2,098	3
411	6,293	1,573	4
412	2,112	106	20
413	120	3	40
414	6	6	1
415	392	196	2
416	785	785	1
417	3,000	3,000	1
418	500	2	250
419	200	4	50
420	1,393	63	22
421	1,393	15	91
422	1,393	348	4
423	1,000	1,000	1
424	100	2	50
425	2,112	2,112	1
426	800	800	1
427	1,000	1,000	1
428	100	2	50
429	128	1	100
430	9	2	4
431	3,000	600	5
432	300	5	60
433	1,000	2	500
434	5,000	5,000	1
435	5,000	5,000	1
436	10,000	5,000	2
437	4,000	4,000	1
438	5,000	2,500	2
439	400	400	1
440	4,500	4,500	1
441	2,112	1,056	2
442	1,000	1,000	1
443	400	400	1
444	5,000	5,000	1

Circuit	PV Total KW	PV Size (KW)	Number of Units
445	6	6	1
446	100	100	1
447	500	25	20
448	2,053	1,027	2
449	48	48	1
450	4,000	4,000	1
451	15,000	15,000	3
452	2,112	2,112	1
453	2,112	2,112	1
454	410	41	10
455	410	410	1
456	48	48	1
457	48	48	1
458	96	96	1
459	48	48	1
460	5,000	5,000	1
461	5,000	5,000	1



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